NEW YORK INDEPENDENT SYSTEM OPERATOR
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December 29, 2014

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Agency Building 3, 19th Floor
Albany, NY 12223-1350

Subject: **Case No. 14-E-0454 -** In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration

Case No. 12-T-0502 - Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades

Case No. 13-E-0488 - In the Matter of Alternating Current Transmission Upgrades - Comparative Proceeding

Case No. 13-T-0454 - Application of North America Transmission Corporation and North America Transmission, LLC for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII of the Public Service Law for an Alternating Current Transmission Upgrade Project Consisting of an Edic to Fraser 345 kV Transmission Line and a New Scotland to Leeds to Pleasant Valley 345 kV Transmission Line

Case No. 13-T-0455 - Part A Application of NextEra Energy Transmission New York, Inc. for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII of the Public Service Law for the Marcy to Pleasant Valley Project

Case No. 13-T-0456 - Part A Application of NextEra Energy Transmission New York, Inc. for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII for the Oakdale to Fraser Project

Case No. 13-M-0457 - Application of New York Transmission Owners Pursuant to Article VII for Authority to Construct and Operate Electric Transmission Facilities in Multiple Counties in New York State

Case No. 13-T-0461 - Application of Boundless Energy NE, LLC for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII for Leeds Path West Project

Dear Secretary Burgess:

Submitted for filing herewith in the above-entitled cases are "Comments of the New York Independent System Operator, Inc." in response to the Proposed Rule Making that was published in the November 12, 2014, New York State Register, I.D. No. PSC-45-14-00002-P and related matters in the NYPSC's AC Transmission Proceedings.

Please contact me at (518) 356-6220 or at cpatka@nyiso.com if you have any questions or concerns.

Very truly yours,

/s/ Carl F. Patka

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case No. 14-E-0454, *In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration*

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Comments of the New York Independent System Operator, Inc.

I. Introduction

The New York Independent System Operator, Inc. ("NYISO") is pleased to submit these comments in the above-captioned proceedings. It has prepared these comments for two reasons. First, the NYISO wishes to ensure that the New York State Public Service Commission ("NYPSC") has the benefit of a complete record as it makes the important determinations before it. The NYPSC should recognize that New York's bulk power transmission system and generation fleet is aging, that new and upgraded facilities are needed, and that increased transmission capacity would provide many benefits to New York's power grid, not only in Southeastern New York but in Western New York as well. Second, the NYISO is commenting to correct a number of errors and other inaccuracies in the submissions made by the Hudson Valley Smart Energy Coalition ("HVSEC") and Dr. Gidon Eshel ("Dr. Eshel") in these proceedings.

A. Background

On July 17, 2014, the Federal Energy Regulatory Commission ("FERC") accepted, subject to a further compliance filing to address a few remaining issues, the NYISO's Order No. 1000 Public Policy Transmission Planning Process ("PPTPP"), effective January 1, 2014.   The NYISO made a further compliance filing on September 15, 2014 and is awaiting a further order. Nevertheless, FERC determined that the NYISO should not defer the PPTPP but should commence it in the NYISO's current planning cycle. That cycle began with a Reliability Needs Assessment in the Reliability Planning Process ("RPP") that started in January.[1]

The first step in the PPTPP is the NYISO's solicitation of proposed Public Policy Transmission Needs ("PPTN") for consideration by the NYPSC. The NYPSC determines the PPTNs for which the NYISO should solicit projects.[2] On August 15, 2014, the NYPSC issued a *Policy Statement on Transmission Planning for Public Policy Purposes* to establish procedures "to guide the transmission planning process for public policy purposes."[3]

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[1] *New York Independent System Operator, Inc*., 148 FERC ¶ 61,044 (2014).

[2] See NYISO Open Access Transmission Tariff (OATT) §§ 31.4.2 and 31.4.2.1.

[3] NYPSC Case No. 14-E-0068, *Policy Statement on Transmission Planning for Public Policy Purposes* (August 15, 2014), at 3.

On August 1, 2014, the NYISO issued a letter inviting stakeholders and interested parties to submit proposed PPTNs to the NYISO on or before September 30, 2014. Under the NYISO's OATT, "[a]fter the end of the 60-day period, the ISO will post all submittals on its website, and will submit to the NYDPS/NYPSC all submittals proposed by stakeholders, other interested parties, and any additional transmission needs and criteria identified by the ISO."

On October 3, 2014 the NYISO filed with the NYPSC Secretary eight proposals for PPTNs provided to the NYISO by: (i) H.Q. Energy Services (U.S.), Inc. (ii) Iberdrola, USA, Inc.; (iii) National Grid; (iv) New York Power Authority; (v) New York Transmission Owners (not including Long Island Power Authority); (vi) NextEra Energy Transmission New York, Inc.; (vii) North America Transmission, LLC; and (viii) New York State Electric and Gas Corporation and Rochester Gas and Electric Corporation.[4]

On November 12, 2014, the NYPSC published in the New York State Register a notice soliciting public comments on the proposed PPTNs by December 29, 2014. On the same day, the HVSEC filed a document entitled *NYPSC Competitive AC Transmission Line Article VII Cases: The Facts* in NYPSC Case No. 12-T-0502, *Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*, and related proceedings addressing potential transmission upgrades in New York State. On November 18, 2014, Dr. Eshel, a geophysicist and mathematician at Bard College, submitted into the record of the same proceedings a paper entitled, *Hudson Valley Transmission Line Plan: Assessing Need & Alternatives*.

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[4] The NYISO has posted these submittals on its website at the following location: <http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp> under "Planning Notices."

B. The NYISO's Interest and Position in these Proceedings

The NYISO is an independent not-for-profit entity that is responsible for the reliable operation of the bulk power transmission system in New York State, for planning for that system's continued reliability, and for administering competitive wholesale electricity markets. Because of those responsibilities, the NYISO has a keen interest in the policy issues in these proceedings. The NYISO has no financial interest in the NYPSC's rulings or in the construction of new transmission infrastructure. It has no affiliation with the NYPSC, any transmission project sponsor, or any other entity. The NYISO is not advocating the identification of any particular PPTN by the NYPSC or any particular transmission project that may be proposed to address a PPTN. The NYISO recognizes that the NYPSC is examining non-transmission alternatives and policies that could either mitigate or increase the need for transmission system upgrades, including the Reforming the Energy Vision, Clean Energy Fund, and New York SUN initiatives.

II. Comments

A. New York's Energy Infrastructure Is Aging and in Need of Replacement to Meet Expected Future Needs

The New York State bulk power system is reliable today and, under conditions that exist at this time, is expected to continue to be reliable for the remainder of the NYISO's ten year planning horizon.[5] But this does not mean that there is no need for new transmission or generation infrastructure to meet the expected future needs of New York consumers. The NYISO Reliability Needs Assessment examines only violations of minimum transmission

[5] *See, e.g., NYISO: Market Developments Postpone Reliability Needs, in NYISO media room at:* http://www.nyiso.com/public/webdocs/media_room/press_releases/2014/ (explaining that recent developments in response to price signals from the NYISO-administered markets have addressed reliability needs that would have otherwise begun in 2019.)

system reliability standards. Having sufficient transmission to avoid violations does not mean that transmission upgrades would not provide important reliability benefits to New York's power grid. In reality, New York's transmission infrastructure is aging and needs to be upgraded and replaced. Transmission upgrades would bring many necessary and important benefits. As explained below, claims to the contrary are not credible or accurate.

Earlier this year, NYISO published *Power Trends 2014: Evolution of the Grid* ("*Power Trends 2014*").[6] This annual publication is designed to contribute to an informed discussion of energy policy. *Power Trends 2014* clearly highlights the need to update the transmission system. Over three-quarters of New York State's high voltage transmission lines are over thirty five years old, having gone into service before 1980. Given the age of the infrastructure, roughly 4,700 circuit miles of the 11,000 circuit miles in the system will need to be replaced over the next three decades at a projected cost of $25 billion.[7] *Power Trends 2014* explains that there are challenges serving the "historically congested areas of the Lower Hudson Valley, New York City, and Long Island" and that the adding transmission and other resources to serve those regions "would alleviate congestion, help avoid future reliability problems, lower consumers' energy costs, and enhance operational flexibility."[8]

Power Trends 2014 also references the *Energy Highway Blueprint ("Blueprint")* issued by Governor Cuomo in 2012. The *Blueprint* recommended actions and policies to attract significant investments in New York State's energy infrastructure. It called for 3,200 megawatts

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[6] POWER TRENDS 2014: EVOLUTION OF THE GRID (New York Independent System Operator, 2014) *available at* <http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/ptrends_2014_final_jun2014_final.pdf.>.

[7] *Id.* at 29 and 31, *citing New York State Transmission Assessment and Reliability Study Phase II Study Report, STARS Technical Working Group* (March 30, 2012).

[8] *Id.* at 5.

(MW) of new generation and transmission capacity, funded by an investment of up to $5.7 billion in public and private funds. It added that cost-effective upgrades along existing transmission corridors could provide 1,000 MW of additional transmission capacity between upstate and downstate New York.

Beyond transmission issues, reliability in New York State currently depends, in part, on older and relatively high-emitting power plants. Due to their age, such plants may become unavailable from sudden catastrophic equipment failure. Moreover, the cumulative effect of increasingly-stringent environmental emission control requirements may make some of the plants the NYISO relies upon in its ten-year reliability plan vulnerable to retirement during the planning horizon between 2015 and 2024. [9] Finally, the future of the 2,000 MW Indian Point nuclear power plant remains uncertain due to ongoing relicensing proceedings before the Atomic Safety Licensing Board and related water permit issues before the New York State Department of Environmental Conservation.

Economic signals emanating from the NYISO-administered markets have resulted in the replacement of much of the older generating capacity with newer and cleaner resources. This trend is expected to continue in the future. [10] It is likely to accelerate given market conditions,

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[9] These programs include: (i) the Cross State Air Pollution Rule; (ii) Maximum Available Control Technology for Mercury; (iii) Best Available Control Technology for regional haze; (iv), Reasonably Available Control Technology for nitrogen oxide emissions; and (v) the proposed EPA Clean Power Plan to address climate change through reduction of power plant carbon dioxide emissions. *See also, Comments of the New York Independent System Operator, Inc. on the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Docket ID No. EPA-HQ-OAR-2013-0602 at 7-8 (Dec. 1, 2014) (describing the challenges New York will face as result of increased environmental regulation.)

[10] *See Introductory Comments of Stephen G. Whitley, President and Chief Executive Officer, New York Independent System Operator, Inc.,* Joint Technical Conference on New York Markets & Infrastructure, FERC Docket No. AD14-18-000 (Nov. 5, 2014) at 2 (noting that the NYISO's locational energy and capacity price signals have incented the construction of generation "in the right places," including "significant new entry in southeast New York, the State's load center.")

e.g., low natural gas prices that favor more efficient units, and the anticipated cost impacts on older generators of new environmental regulations. Increased transmission capacity would help the NYISO to successfully manage the transition in the generation fleet and lay the foundation for maintaining long-term reliability in the future.

B. Transmission Upgrades Would Bring Numerous Benefits to New York State

HVSEC and Dr. Eshel have, essentially, argued that increased transmission capacity in the Lower Hudson Valley would bring minimal or no benefits. This is not a tenable position. Evidence supporting the benefits of transmission is readily available. Indeed, it would be reasonable for the NYPSC to take administrative notice of the fact[11] that new transmission infrastructure would be beneficial, particularly for regions, like the Lower Hudson Valley, that have historically experienced congestion.

For example, a July 2013 report by the Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments* ("Brattle Report") highlights the broad range of benefits that may be created by new and upgraded transmission infrastructure. Many of these benefits are commonly overlooked in favor of an overly narrow focus on traditional production cost savings analysis. They include:

- "Additional Production cost Savings" associated with:
  - Reduced transmission energy losses
  - Reduced congestion due to transmission outages
  - Mitigation of extreme events and system contingencies
  - Mitigation of weather and load uncertainty

[11] Courts have held that regulators need not demand proof that broadly accepted facts are true. *See, e.g., Associated Gas Distribs. v. FERC*, 824 F.2d 981, 1008-09 (D.C. Cir. 1987) ("Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall . . . .")

- Reduced cost due to imperfect foresight of real-time system conditions

- Reduced cost of cycling power plants

- Reduced need for (and costs of) ancillary services

- Mitigation of the need to rely on "Reliability Must Run" contracts or similar arrangements

• Reliability and resource adequacy benefits, including:

  - Avoided or deferred reliability projects

  - Reduced loss of load probability or reduced planning reserve margins

• Generation capacity cost savings, including reduced peak energy losses, deferred capacity investments, and access to lower cost resources

• Market benefits including increased competition and market liquidity

• Environmental benefits including reduced air emissions (by facilitating reliance on cleaner resources) and improved utilization of transmission corridors

• Reduced costs of meeting public policy goals

• Increased employment and economic activity (which can also result in increased tax revenues)."[12]

HVSEC and Dr. Eshel have overlooked virtually all of these benefits. By contrast, the NYISO recognizes that many of them would likely be realized in New York if new transmission were added to the bulk power transmission system in an appropriate manner. Among other things, new transmission capacity would enhance competition in the markets by allowing new resources to compete and increasing liquidity. It would make the system more resilient and able to withstand extreme weather conditions and storms. These include the traditional challenges presented by summer peaks on hot days as well as the less familiar issues that can arise during winter "polar vortex" events. Increased transmission would also give the NYISO greater

[12] Brattle Report at 10 (Attached as Exhibit A).

operational flexibility, *e.g.*, by making it easier to dispatch resources, gain access to operating reserves and ancillary services, and remove transmission from maintenance when needed.

Increased transmission capacity would further advance the integration of renewable energy resources in New York State. In the last year New York has seen substantial growth in wind power and hydropower. In 2014, wind power capacity increased seven percent over 2013, reaching 1,730 MW of capacity. Wind generation grew by 16%, reaching 3,541 gigawatt-hours of electricity.[13] Most of this growth in capacity and output is taking place upstate and in the western portion of New York. However, the demand lies in the Lower Hudson Valley, New York City and Long Island regions. More transmission capacity would increase the NYISO's ability to dispatch renewable resources more frequently. That would help to attract additional renewable development while lowering emissions.[14]

Similarly, adding transmission would help to take better advantage of fuel diversity. Compared to other parts of the country, New York State has a relatively diverse mix of generation resources. However, much of that diversity exists in Upstate New York while downstate generation is principally comprised of natural gas-fired or dual fuel units capable of burning natural gas or fuel oil. This is illustrated by Figure 1 below.

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[13] *Power Trends 2014* at 9.

[14] *See* 2010 NYISO Wind Study, Section 5.7 at <http://www.nyiso.com/public/webdocs/services/planning/special_studies/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf>.

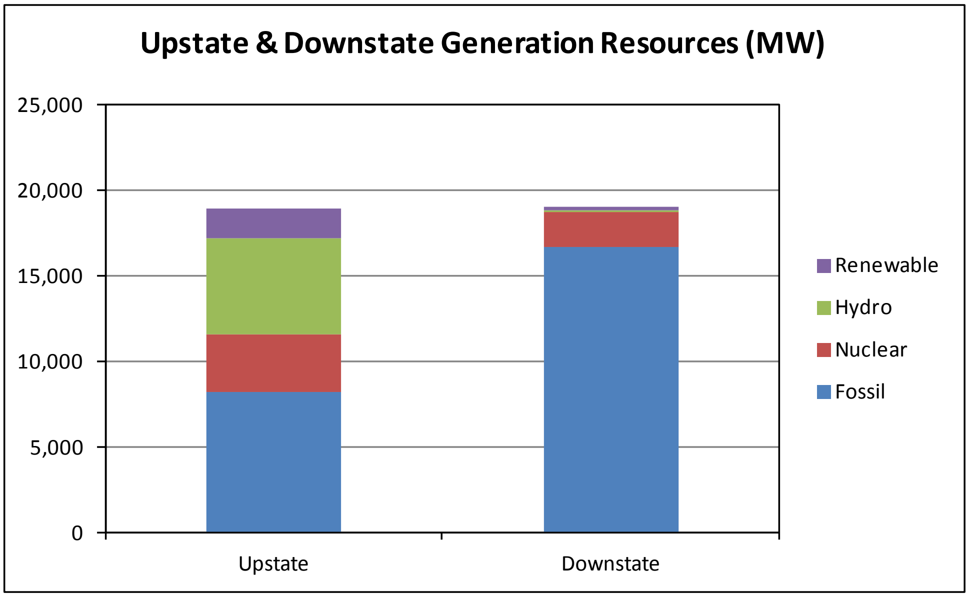

Figure 1 – Upstate and Downstate Generation Resources

Moreover, available supply in upstate New York exceeds the region's peak load whereas the reverse is expected to be true downstate at peak load during Summer 2015. This is clearly shown in Figure 2 below.

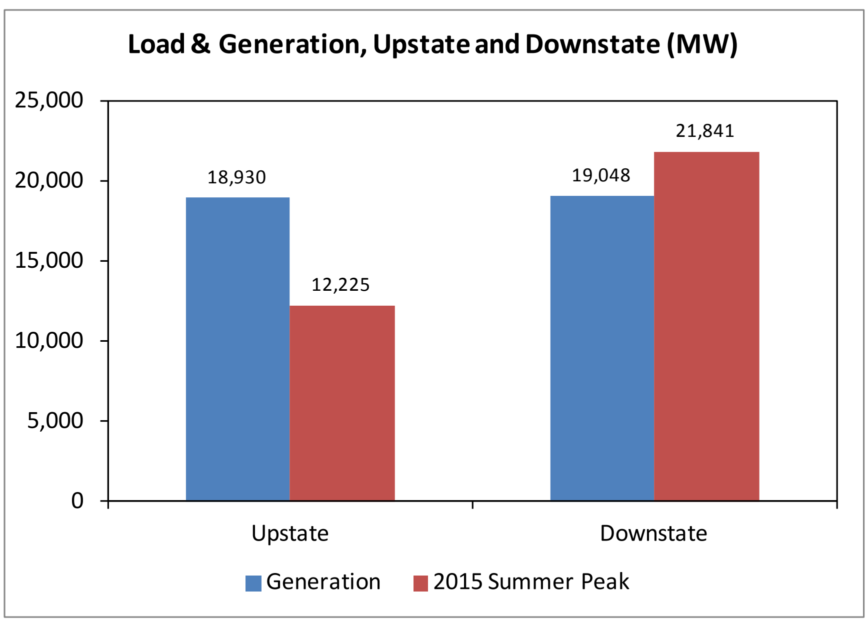

Figure 2 – Upstate and Downstate Load and Generation

Although limited transfer capability exists into downstate New York from neighboring regions in New England and PJM, an effective way to address the regional imbalances between upstate and downstate New York would be to add transmission capacity that increases the ability of upstate resources to serve downstate loads.[15]

The NYPSC should bear in mind that the Upstate to Downstate transmission paths are not the only areas in need of additional transmission capacity. It is also imperative to improve the bulk power transmission system's ability to move power from the Niagara Power Project and other major economic resources located in Western New York to Eastern New York. This area of the transmission system is constrained today, depriving New Yorkers of the full amount of clean and economic resources that could otherwise be enjoyed. Transmission capacity is needed to address these constraints. The need will only increase as older generation retires and must be replaced in the Eastern and Southern portions of the state.

C. Correcting HVSEC's Errors and Inaccuracies for the Record

1. The Purpose of the AC Transmission Proceedings

HVSEC suggests that the sole purpose of the AC Transmission Upgrades proceeding is to reduce costs to downstate customers by adding 1,000 MW of transmission capacity to relieve "historic" congestion across the Central-East constraint. While it is true that transmission capacity additions should result in lower costs, it is inaccurate to imply that this would be their only benefit. As is emphasized throughout these comments, incremental transmission additions would improve reliability, make markets more efficient, and serve various public policy

[15] *Power Trends 2014* at 9; *citing* studies by the NYISO; the State Transmission Assessment and Reliability Study conducted by the New York Transmission Owners; and Governor Cuomo's New York Energy Highway initiative.

objectives, such as transmitting energy from more renewable resources, lowering air emissions, and making the transmission grid more resilient.

2. Reliability

The NYISO agrees with HVSEC that "[t]he reliability and safety of our energy grid is extremely important." But HVSEC is wrong to suggest that new and upgraded transmission would not benefit reliability in the Lower Hudson Valley.

As stated above, it is true that the NYISO has found that the current transmission system is sufficient to meet minimum reliability needs. But that does not mean that there would be no reliability benefit to having a system that is more reliable than the minimum standards require. The NYPSC has previously recognized that is important to foster investment in generation resources above the minimum necessary to satisfy applicable requirements.[16] Having transmission infrastructure above the minimum required is equally important.

For the RPP, the NYISO assesses whether there are sufficient generation resources and transmission facilities to meet the minimum reliability requirements over the time period studied. The NYISO makes its assessment for the RPP based on a very specific set of assumptions; it also reviews a series of potential scenarios and sensitivities under which reliability concerns were identified. Expanding the bulk power transmission system as contemplated in these proceedings would better position the system to mitigate potential threats to reliability.

More generally, it is simply not plausible for HVSEC and Dr. Eshel to suggest that new Lower Hudson Valley transmission would have no reliability benefit given the potential closure

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[16] *See, e.g., Written Statement of Emilie Nelson,* Docket No. AD14-8-000 at 4 (November 5, 2014) ("In 2002 and 2003, the NYPSC proposed that the NYISO adopt a sloped demand curve to recognize the marginal reliability value of maintaining incremental capacity resources beyond the minimum needed to comply with reliability requirements.") (citations omitted).

of Indian Point Nuclear Generating Units 2 and 3 ("Indian Point"), which are up for relicensing before the U.S. Atomic Safety Licensing Board. [17] If Indian Point were to close, downstate New York would lose more than 2,000 MW of generating capacity, resulting in immediate reliability standard violations as well as the loss of fuel diversity depicted in Figure 1 above. In that scenario, it would be all the more vital to have the increased North to South transmission capability that only significant transmission expansion would make possible. The Transmission Owner Transmission Solutions ("TOTS") projects currently being pursued by Consolidated Edison Company of New York, Inc., the New York Power Authority, and New York State Electric and Gas Corporation in accordance with the NYPSC's November 4, 2013 Order[18] would address to some degree the system need that would exist if Indian Point retires. But the TOTS projects would not provide a complete replacement for Indian Point's capacity.

3. Congestion Costs

HVSEC also asserts that the most recent NYISO Congestion Assessment and Reliability Integration Study ("CARIS") militates against moving forward with new transmission development in the Lower Hudson Valley. While the historic data cited by HVSEC are accurate, as far as they go, they are misleading in two respects.

First, the congestion costs cited are limited to those costs associated with the Central-East constraint. They do not include historic congestion costs across the entire interface that would be impacted by the transmission projects that the NYPSC is considering in these proceedings. More specifically, the congestion costs for Leeds-Pleasant Valley should be included for an

[17] *See In the matter of Entergy Nuclear Operations, Inc., (Indian Point Nuclear Generating Units 2 and 3)*, Docket Nos. 50-247-LR and 50-2860LR, Atomic Safety and Licensing Board, Nuclear Regulatory Commission.

[18] NYPSC Case No. 12-E-0503, *Order Accepting IPEC Reliability Contingency Plans, Establishing Cost Allocation and Recovery, and Denying Requests for Rehearing* (Nov. 4, 2013).

accurate representation of the impacted congestion dollars. Including them yields congestion costs of $392 million for 2012 (versus the $255 million cited by HVSEC).

Second, the historic period cited by HVSEC ends in 2012. Total congestion in the New York Control Area actually increased significantly in 2013 from 2012 and remained at this elevated level through the first three quarters of 2014. Due to the cold winter conditions, congestion across Central-East was very high during Winter 2013/2014.

In fact, congestion costs are highly dependent upon weather and economic conditions and vary significantly from year-to-year. It may be prudent to invest in the infrastructure to hedge against such volatility and long-term cost escalation. Basing such long-term decisions on a single historic year (as HVSEC suggests) is problematic. Moreover, the economic benefits of new transmission are not limited to reduced congestion costs. The NYISO's OATT requires that New York system-wide production cost savings be the sole metric for the evaluation of the economic benefit of projects in the CARIS process. But capacity market benefits, *i.e.*, reductions in statewide and local capacity requirements, are another important way that congestion relief is good for consumers. Such capacity market savings could result from reduced statewide or locational installed capacity requirements when transmission upgrades are added to the system.

Finally, to the extent that new transmission alleviates congestion, it would, as noted above, enhance the NYISO's ability to manage the system during extreme weather and storms. Such improvements should reasonably be expected to lead to substantial savings for consumers.

4. Planned and Future Resources

HVSEC claims that "[c]urrently planned generating and transmission resources will meet predicted electricity demand" because there are "currently 30 projects in the NYISO Interconnection Queue as of September 30, 2014, that will provide approximately 9,500 megawatts in generating and transmission capacity south of the Central-East Constraint." It goes so far as to assert that "[i]f you deduct 2,020 megawatts for the shutdown of Indian Point and assume only 50 per cent of these projects come on line, there is still almost a 4,000 MW margin of safety relative to the 1,000 MW proposed by the Energy Highway."

HVSEC appears to have counted multiple proposed projects that are included in the interconnection queue to address the same need and to have included projects that would not address the resource deficiency in the area south of the constrained Upstate New York to Downstate New York (UPNY-SENY) interface when it devised its 9,500 MW estimate. The theoretical maximum output of all potential generation projects in the interconnection queue proposed for the region below the UPNY-SENY interface is roughly 3,500 MW, not 9,500 MW. Moreover, experience demonstrates that well less than fifty percent of this subset of potential projects will actually be built. Adjusting for this and for other factors, *e.g.*, units known to be returning to service, the potential unavailability of Indian Point, and unit outage rates, the New York Control Area ("NYCA") could have a reliability need of approximately 1,000 MW or greater in 2024 rather than the surplus of 3,990 MW that HVSEC claims.

It should be noted that this possible reliability need is based on a load forecast certainty interval at the 50th percentile. If New York were to experience a summer peak load at the 90th percentile, the system need in 2024 would be significantly higher.

HVSEC has also overlooked the material distinction between facilities that secure a spot in the NYISO interconnection queue and those that are sufficiently likely to actually be constructed to be relied upon in the NYISO planning processes. The generation queue is designed to organize developer's exploratory study requests. The interconnection studies provide information to developers concerning the cost and technical issues involved in developing their conceptual projects. The study queue does not require any commitment by developers to proceed with any projects and it is, therefore, not a reliable indicator for determining what may be developed. It is for these reasons that specific rules have been adopted for use in the NYISO's reliability planning studies to identify facilities that have received necessary regulatory approvals or are actually under construction. It is also important to recognize that whether these projects move forward depends upon a host of reasons which may or may not be directly linked to the need to maintain system reliability or relieve congestion.

5. Impact of the "New Capacity Zone"

The NYISO agrees with HVSEC that the implementation of the G-J Locality, which is often informally referred to as the "New Capacity Zone," has encouraged the return of needed generation. As HVSEC notes, the New Capacity Zone should also be expected to contribute to reduced congestion costs in the future. These benefits do not preclude the proposed AC transmission upgrades from creating additional reliability and congestion benefits.

6. Public Policy Justifications

Finally, HVSEC asserts that there is no public policy justification for the NYPSC's initiative because the NYISO OATT states that "a project must be justified by a federal, state or local law or regulation supporting a public policy goal." HVSEC claims that "there are currently no laws or regulations that support a public policy justification."

This claim is perfectly circular. The current NYPSC proceedings constitute the very regulatory process that FERC intended, and the NYISO OATT requires that the NYISO must account for, as part of New York's "public policy" planning obligations under Order No. 1000. If the NYPSC exercises its prerogative to identify one or more transmission needs based upon public policy considerations after notice and comment under the State Administrative Procedure

Act, then there is no question that its decision would constitute a "state regulation" and therefore a Public Policy Requirement that can drive a Public Policy Transmission Need under the NYISO OATT.[19]

D. Dr. Eshel's Analysis Is Based upon Inaccurate Assumptions, Is Flawed, and Reaches Invalid Conclusions

Dr. Eshel's paper argues that there is no "discernible evidence" that "additional generation or transmission capacity is needed in New York's downstate region."[20] Dr. Eshel contends that the NYPSC should not move forward with its proceedings absent a "technically vetted and fully transparent scientific demonstration of need."[21] Putting aside Dr. Eshel's lack of justification for replacing traditional criteria for evaluating projects and regulatory policies with an unspecified "scientific demonstration" standard, his analysis is fundamentally flawed. Below, the NYISO respectfully addresses some of the most significant errors that disregard electric power system realities and widely accepted industry planning standards.[22]

Dr. Eshel's model of peak demand for NYISO Load Zones G to K is overly simplistic and misleading. It is based on population, maximum temperature and the ratio of the population age-group cohort of 20 to 45 year olds to the age-group cohort of those 45 to 70. In his

[19] *See, e.g.*, New York Independent System Operator, Inc. and New York Transmission Owners, *Compliance Filing*, Docket No. ER13-102-000 at 39 (October 11,2012) (explaining that "the NYPSC has the primary responsibility for the identification of transmission needs driven by Public Policy Requirements. The NYPSC is also the entity that determines which proposed transmission solutions should seek the necessary local, state, and federal authorizations for construction and operation."); *New York Independent System Operator, Inc*., 143 FERC ¶ 61,059 at PP 141-42 (2013) (accepting proposal to permit the NYPSC identify the transmission needs driven by public policy requirements as compliant with Order No. 1000).

[20] Eshel at 2, 29

[21] Eshel at 3.

[22] The NYISO's silence regarding any of Dr. Eshel's assertions should not be construed as support for or acquiescence to them. There are other flaws in Dr. Eshel's analysis that are not addressed here.

preliminary model building stage, he concluded that "downstate peak electricity load is unrelated to affluence, but significantly related to the other five tested predictors" (which included population and maximum temperature).[23]

For purposes of comparison, Figure 3 below shows historic data for the Load Zones G to K coincident summer peak demand and a series of four macro-economic variables: population, employment, GDP and per-capita GDP (Dr. Eshel's affluence variable) using data from Moody's Analytics. Based on these data, the NYISO produced four separate two-variable models, using one macro variable and a temperature-humidity heat index (comparable to maximum temperature). Figure 4 illustrates that the NYISO found that the model using population has the worst r^2 coefficient whereas the affluence variable has the best. This is consistent with more than a decade of NYISO modeling experience which, in keeping with established utility industry practice, considers GDP to be a more significant variable than either population or employment in most cases. This is also indicated by the much lower model errors using GDP or GDP-per-capita, which are shown in Figure 5. When regressed against the *weather-normalized* peaks (rather than actual peaks) the r^2 coefficient for a model using GDP alone will sometimes exceed 0.90. It is therefore clear that Dr. Eshel's model based upon population, maximum temperature and the ratio of two population cohorts is far from ideal. Accordingly, his forecast should not be given much weight, on modeling grounds alone.

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[23] Eshel at 18.

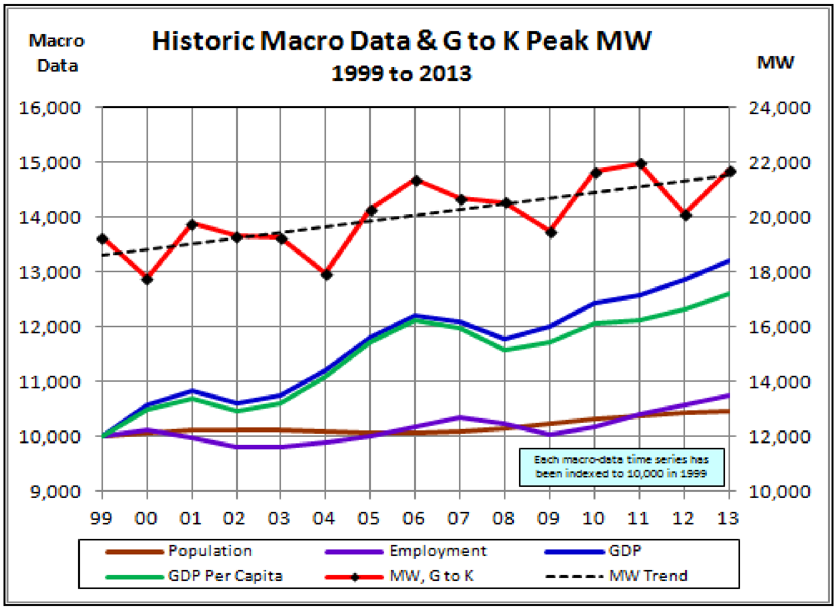

Figure 3 – Peak Loads & Macro Data

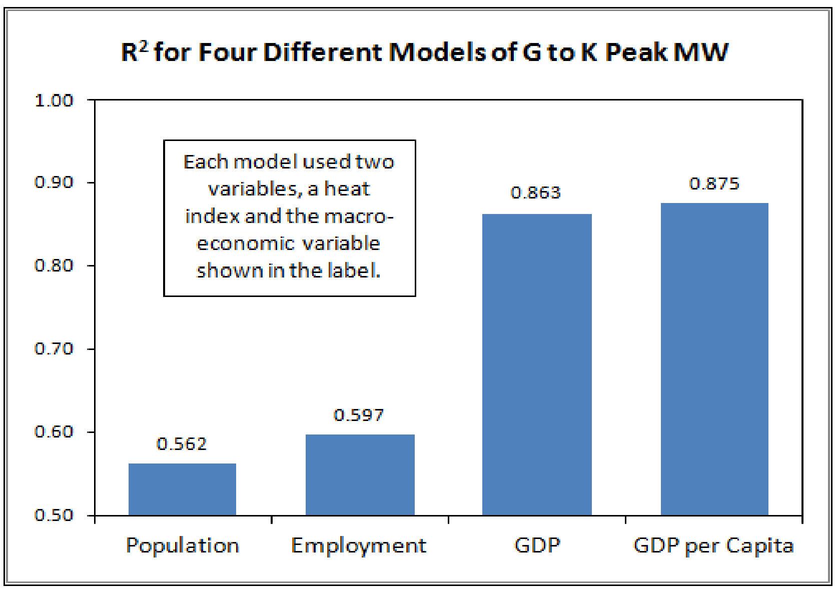

Figure 4 – r^2 of Four Different Models of G to K Peaks

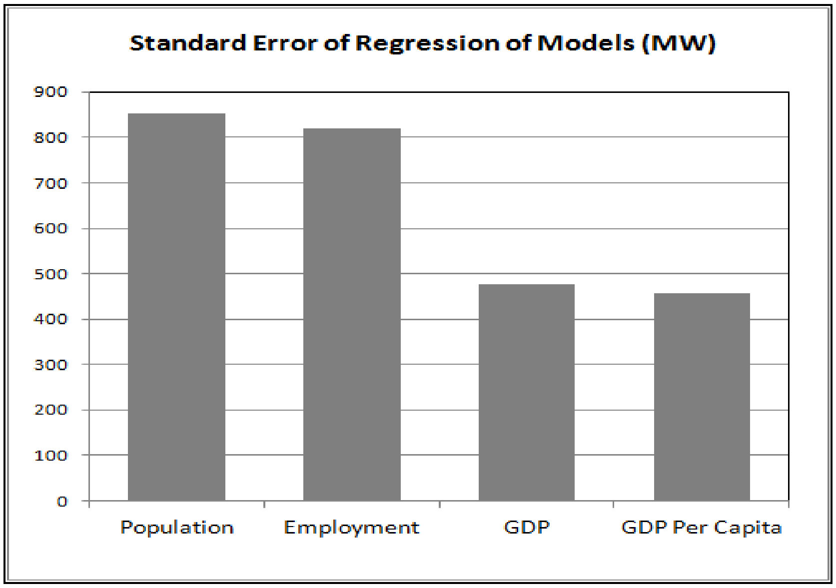

Figure 5 - Standard Error of Each Model

Figure 6 presents a comparison of Dr. Eshel's forecast and the NYISO's 2014 CARIS forecast (extended by one year to 2035). The NYISO's forecast is higher that Dr. Eshel's baseline forecast and corresponds to the upper bound of Dr. Eshel's estimates.[24] Dr. Eshel's 2015 forecast starts 1,000 MW lower than the NYISO's. There are multiple good reasons why the NYISO's forecast is higher; including that the first year of Dr. Eshel's forecast does not correspond to the weather-adjusted peak for that year. The NYISO just completed a 2015 forecast in cooperation with the New York Transmission Owners. It found that the weather-normalized peak in Load Zones G to K in summer 2014 was 21,670 MW, and projected a summer weather-normalized 2015 peak of 21,879 MW.

[24] Eshel at Fig 8.

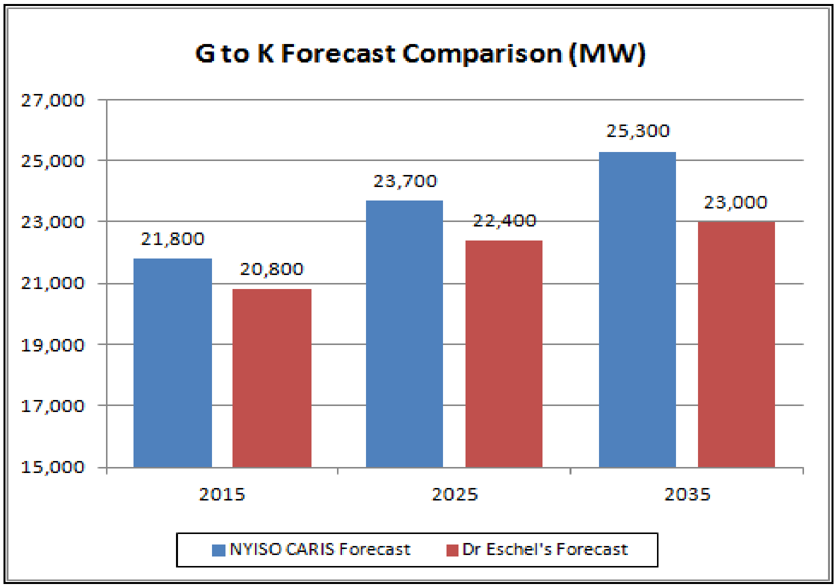

Figure 6 – Comparison of NYISO & Dr. Eshel's Forecasts

In addition, Moody's Analytics projects population in Load Zones G to K to grow by 1.90% from 2014 to through 2024, whereas employment is expected to grow by 6.2%, GDP by 25% and per-capita GDP by 22%. These data are significant because growth in GDP or per-capita GDP is indicative of expansion in business activity, construction of commercial and industrial floor space, and associated equipment and residential home construction. Therefore, it is not surprising that the NYISO's 2025 forecast exceeds Dr. Eshel's 2035 forecast, since per-capita GDP growth is an order of magnitude greater than population growth alone.

However, GDP does not tell the entire story of the NYISO's load forecast. The NYISO's forecast also includes explicit reductions for energy efficiency based upon historical achievements, authorized NYPSC budgets for the Energy Efficiency Portfolio Standard, and estimated outlays beyond the last year of authorized spending. The future potential for energy efficiency of 0.9% to 1.5% per year cited by Dr. Eshel[25] is also higher than the actual annual impacts observed over the past two years, which were about 0.7% per year, statewide.

[25] Eshel at 24-25.

To summarize, the differences between Dr. Eshel's forecast and the NYISO's are attributable to a lower starting point and the selection of population instead of GDP or GDP-per-capita. Once these are accounted for, Dr. Eshels' forecast would be reasonably close to the NYISO's.

Assuming that the upper bound of Dr. Eshel's forecast was accepted as the basis for examining the need for resources in Load Zones G to K, he would still conclude that no additional transmission or generation resources were needed. This conclusion is based on three factors:

1. an assumption that half of the potential projects in Load Zones G to K that are listed the NYISO queue will be completed;
2. additions of energy efficiency resources at a rate of 0.9% per year; and
3. the closure of Indian Point.

First and foremost, a simple graphical comparison of a peak load forecast to the available generation and transmission resources in a limited geographic area is not consistent with accepted engineering principles for performing an evaluation of the bulk power system. The future power requirements for Load Zones G to K cannot be examined in isolation from the rest of the power grid. Robust system planning examines transmission security, congestion, extreme weather conditions, forced generator outages, availability of resources from neighboring systems, and a host of other contingencies. System planning studies are based upon science, upon engineering standards and upon public policy set forth by the NYPSC, the New York State Reliability Council, FERC, the North American Electric Reliability Corporation ("NERC"), and the Northeast Power Coordinating Council ("NPCC").

Power Trends 2014 demonstrated that during Summer 2014 total New York resources exceeded system requirements by more than 1,900 MW. As of April 2014, the NYISO queue listed 9,767 MW of new projects in Load Zones G to K, half of which is about 4,900 MW. Dr. Eshel supposes that generation and transmission resources will increase by roughly this amount, *i.e.*, 4,900 MW, from 2015 to 2020, or by approximately 980 MW per year. Dr. Eshel provides no explanation of why it would be reasonable to assume that half of the projects in the queue will be built, and it is the NYISO's experience that less than half of queue projects are actually built. As explained above, the theoretical maximum output of all potential generation projects in the interconnection queue proposed for the region below the UPNY-SENY interface is roughly 3,500 MW, not 9,500 MW. Adjusting for this and for other factors, *e.g.*, units known to be returning to service, the potential unavailability of Indian Point, and unit outage rates, the NYCA could have a reliability need of approximately 1,000 MW or greater in 2024 rather than the surplus of 3,990 MW that HVSEC claims.

Moreover, were Indian Point to become unavailable by late 2015, the pool of available resources in Dr. Eshel's analysis should be decreased by about 2,000 MW in 2016. Numerically, this would result in resources falling short of 2014 requirements, in the absence of any other additions. Dr. Eshel has also failed to consider the potential for future plant retirements during the twenty year period he examines, and does not address the issues caused by aging transmission infrastructure in New York.

In short, Dr. Eshel's report and analysis consists of the following elements; a statistically generated forecast of peak demand and a chart. The graphical comparison of the forecast to a projection of potential new projects is based upon incorrect arithmetic that does not correspond to one of his stated assumptions – *i.e.*, that Indian Point will be retired. This approach is unsound and inconsistent with engineering considerations described in Section II(B) above that would make the development of new transmission infrastructure in New York beneficial. For all of the above reasons, the NYISO submits that Dr. Eshel has not provided an accurate or realistic forecast of peak loads in the Zones G to K, nor has he provided a credible assessment of the region's reliability needs of the region from a bulk power system planning perspective.

III. Conclusion

For the foregoing reasons, the NYISO respectfully requests that the New York State Public Service Commission consider these comments in determining Public Policy Transmission Needs and in its deliberations in the Alternating Current Transmission Upgrade proceedings.

Respectfully submitted,

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December 29, 2014

Attachment A

A WIRES Report

on

The Benefits of Electric Transmission:

Identifying and Analyzing the Value of Investments

The Brattle Group

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WIRES

The Brattle Group

July 2013

www.WIRESgroup.com

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WIRES Preface and Commentary

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

Summary of Peer Review of *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*

WIRES Preface and Commentary

WIRES[1] commissioned this report to address an emerging practical and theoretical question tied to the effective planning and construction of the electric transmission system: What are the potential benefits of a transmission project or portfolio of projects and can those benefits be ascertained and measured for purposes of planning and cost responsibility? To summarize, this report is designed to accomplish three objectives:

(1) To catalogue all the potential benefits[2] of transmission that can, and arguably should, be identified, considered, and estimated in planning the expansion or upgrade of the grid, based on the growing experience of transmission planners across the country;

(2) To document the evolving experience and practice of regional transmission organizations (RTOs) and non-RTO regions in determining the economic, reliability, operational, and public policy benefits of transmission investments based on their physical and operational characteristics, location,

[1] WIRES is a national non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. WIRES members include integrated utilities, regional transmission organizations, independent and renewable energy developers, and engineering, environmental, and policy consultants. WIRES principles and other information are available on its website: www.wiresgroup.com.

[2] "Benefits" are anything "advantageous or for the good of" individuals or groups of people ("beneficiaries"). The Brattle report addresses a variety of benefits in the energy delivery environment that range from those which immediately result from costs incurred for a specific service (*e.g.*, interconnection) to benefits with broader or long-term impacts from improvements or extensions of a shared system (*e.g.*, competitive access to markets or resources, congestion relief, or increased reliability).

technology, surrounding markets, prevailing regulation, and environmental and economic impacts; and

(3) To evaluate how planners and policy makers may employ transmission benefit determinations and calculations to support needed transmission investment across the country. Many of these benefits have not been considered or well understood until fairly recently.

This report is therefore a unique, and we expect uniquely valuable, compilation of transmission's value for, and effects on, the electric system, its customers, and the economy as a whole. But the report's impact and its significance ultimately rests with how the industry and the Commission utilize its ideas in implementation of Order No. 1000 within and between RTO and non-RTO regions, where important differences in planning and cost allocation approaches exist. We offer this study as a basic analytical resource upon which such decision making processes will go forward.

* * * * * *

Today's wholesale or "bulk" electric power system, and the electricity markets it supports, rests upon an increasingly integrated high-voltage network of lines, substations, and control facilities that are planned and constructed by often-diverse entities, serve multiple purposes, and in effect operate across utility system and state, regional, and even international boundaries. The bulk electric power system provides numerous economic, security, environmental, public policy, and reliability benefits to ratepayers across regions and interconnections. Yet some integrated electric utilities continue to build transmission primarily to serve only the reliability needs of customers within their service territories. Either way, decisions about which transmission facilities to build or upgrade (or which non-transmission solutions may be preferable) and how to recover the costs of that new capacity are more complicated today than ever before.[3] Before investing in new infrastructure in any situation, an evaluation of the near- and long-term benefits that additional transmission capacity can provide, and to whom, is fundamental to a rational deployment and allocation of society's resources, good environmental stewardship, fairness to customers (including future generations of customers), and fulfillment of public policies such as fuel diversity, clean energy, economic development, and market competition. Well-planned and timely-built transmission has a decisive and positive impact in all these areas.

Nevertheless, it would be rash to assume that policy makers, transmission planners, and regulators already share a common understanding of transmission's potential benefits or an agreed-upon approach to planning that ensures fair consideration of all the ways these assets could serve the public and the economy during their long, useful lives. Instead, the widespread differences in planning processes and experience suggest that many, or even most, potential benefits are eliminated from consideration at the very outset of the planning process. This outcome is often attributable to the assumption that transmission is generally planned and built for a single discreet purpose or market and that its purpose and usage change very little over the life of the asset. In addition, the prospect of assigning or accepting cost responsibility may profoundly affect judgments about a project and prejudice views of its value. Moreover, measuring all the widespread and diverse impacts of new transmission capacity on an integrated network presents new analytical challenges, and planners may be unfamiliar with ways to estimate or model benefits that heretofore were regarded as remote, speculative, unquantifiable, or simply too difficult to estimate. And finally, regions have very different approaches to identifying and measuring the benefits of transmission.

[3] Modern transmission, like other integrated infrastructure networks, poses novel challenges to planners and policy makers, including how to deploy capital for the maximum benefit of electricity customers sharing the network and whether (and how) particular additions to the grid can be said to benefit specific groups of customers, including those who may not directly "use" the facilities at points in time. *See Midwest ISO Transmission Owners v. Federal Energy Regulatory Commission*, 373 F 3d 1361 (D.C. Circuit, 2004); *Illinois Commerce Commission et al. v. Federal Energy Regulatory Commission*, 576 F 3d 470 (7th Circuit, 2009*); Illinois Commerce Commission et al. v. FERC*, No. 11-3421 (7th Cir., June 7, 2013).

These differences in assumptions and approaches to transmission planning and cost allocation among the regions could devolve into a "lowest common denominator" approach to selecting inter-regional projects, a concern identified in the report. This report offers an alternative and less expedient approach to inter-regional planning agreements that will lead to more economically-efficient investment decisions.

Whether assessing a utility, regional, or inter-regional transmission project, a failure to fully consider all *potential* benefits of a transmission project will lead to uneconomic results. For example, traditional methods of evaluating the need for, or benefits of, transmission projects based primarily on meeting applicable reliability standards will not consider economic benefits. Even when evaluating economically-justified transmission projects, methods that focus on production cost simulations that assume normal weather, no transmission outages, and no change in transmission losses provide an inherently limited economic analysis for new or upgraded transmission. Consideration of other transmission-related benefits (*e.g.*, storm hardening, increased competition in wholesale power markets, congestion relief, deferral of new generation or other upgrades, and numerous other attributes discussed in this report) that could accrue over time provides greater opportunity for implementing the best projects. The narrower or more restrictive the analysis, the greater the likelihood that highly beneficial projects may be rejected and that sub-optimal projects may be accepted in the planning process.

In sum, we think the report constitutes a strong message and recommendation that planners must plan for the highest value first, in response to the industry's extensive and evolving experience developed in recent years and the demands placed on planners by FERC policies. Only then should the question of identifying all beneficiaries and addressing the question of who pays be undertaken. In the final analysis, policy makers, planners, and customers deserve to have confidence that they are realizing the greatest level of transmission benefits for which customers are paying.[4]

We hasten to add that not all transmission projects that are proposed can also be economically justified or should be built and that better use of existing transmission capacity and rights-of-way should be a priority. Non-transmission solutions must be fairly evaluated as well. The tariffs of individual regions approved under Order No. 1000[5] will govern whether a benefits calculus drives or simply informs the planning process and whether all potential benefits are fairly evaluated. So far, the Commission has not been specific about what will be required in those tariffs, but the Commission's ongoing review of the compliance filings may help fill the gaps. As we read Order No. 1000, however, both the transmission planning and cost allocation analyses will in the future take place at the regional and inter-regional levels and will thereby reflect the operation of modern wholesale power markets.[6] For those reasons, WIRES believes that this report will be of special interest to the Commission, system operators, and industry experts who are currently implementing Order No. 1000. The issues raised and the approach suggested herein should also persuade investors and public policy makers of the importance of encouraging investment in stronger electric infrastructure, given the

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[4] The Seventh Circuit Court of Appeals has opined on the role of transmission benefits in public utility ratemaking: "To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed." *ICC v. FERC*, 576 F 3d *at* 476. For a discussion of the relevance of benefits to setting returns on investment, *see* WIRES June 26, 2013 *Petition for Statement of Policy*, Docket No. RM13-18-000. Recognizing that transmission benefits and beneficiaries may not be precisely quantifiable in every case, the court also stated: "We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars." Instead the court instructed regulators to ensure that transmission benefits and cost responsibility are at least "roughly commensurate" with one another. *Id*. at 477.

[5] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

[6] We recognize that certain vertically integrated markets consider transmission benefits in the context of integrated resource planning. It is not the purpose of this report to suggest whether any limitations inherent in such analysis can be, or need to be, reconciled with Order No. 1000. Consideration of all of the benefits of transmission in such markets would still be important to any determination of the public interest and achieving optimal use of resources on the power system.

broad range of benefits transmission is capable of providing to a region, an interconnection, or the nation.

* * * * *

This report is aimed at two distinctly different readerships. First, the lay person or policy maker who comes to the benefits issue without a grounding in public utility operations or economics will find a clear explanation of transmission benefits and their role in the transmission planning process. The Executive Summary will be particularly helpful to them. Its purpose is to make clear that supporting or opposing transmission infrastructure development in the 21st Century has to be about more than opting for what appears to be the cheapest solutions to immediate problems. Second, we believe transmission planners, engineers, and economists will find practical, technical support in these pages for a more efficient and thorough way to identify, consider, and evaluate the multiple benefits of transmission in the planning process. The Brattle Group report thus provides both clarity and depth in its analysis – a difficult challenge to meet.

Finally, WIRES has instituted an important innovation in this report. Appended to the report is an independent evaluation of the work product by four well-known expert economists – one each from academe, an integrated utility, an RTO, and an economic consultancy. These peer reviewers have familiarized themselves with The Brattle Group's analysis and articulated a collective "second opinion" about it. Their review, appended to the report, provides important additional insight into the context and methodologies of transmission benefits determinations. Looking beyond benefits analysis to the increased use of optimization tools in the planning process, the peer reviewers also suggest that transmission planners should institute more "decisional support methodologies" that will help improve planning in response to the grid's growing complexity and the options planners must consider. However, we do not understand these experts to be suggesting that constructing a business case for a transmission project in light of all its potential benefits should be deferred during the continuing search for more perfect analytical tools.

The Brattle Group authors and the peer reviewers would hasten to emphasize, and we therefore repeat here, that the views they express are their own and not necessarily those of their organizations.

* * * * * *

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The Brattle Group

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

July 2013

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Prepared for

WIRES

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Acknowledgements and Disclaimer

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THE BENEFITS OF ELECTRIC TRANSMISSION:
IDENTIFYING AND ANALYZING THE VALUE OF INVESTMENTS

EXECUTIVE SUMMARY

A. SCOPE OF THIS REPORT

WIRES, also known as the **W**orking Group for **I**nvestment in **R**eliable and **E**conomic Electric **S**ystems, engaged *The Brattle Group* to assemble available experience with identifying and analyzing the wide range of potential benefits offered by transmission investments. WIRES has asked *Brattle* to focus on how various benefits can be identified and estimated, and to discuss the experiences of regional transmission organizations (RTOs) and non-RTO regions in analyzing the economic, reliability, public policy, and other benefits that new or upgraded transmission can provide.

Because the recognition and understanding of many of the transmission-related benefits by system planners and regulators has been evolving, there is currently no standard menu of benefit metrics that can be applied in the evaluation of transmission investments. The lack of standard benefit metrics is a critical gap in advancing the planning of an improved power grid. This report attempts to fill that gap.

While we recognize that the evaluation of the merits of transmission projects is inherently linked to a broad set of important and challenging topics, our report is focused on the identification and evaluation of transmission-related costs and benefits. The report is organized as follows:

- Section I provides background, including the purpose and scope of our report.

- For both policy makers and practitioners, Section II discusses the importance of accounting for transmission benefits in the context of the planning process and then summarizes the types of benefits transmission projects may offer. Compiled from a detailed review of industry practices and our own experience, we then present a "checklist of economic benefits" that can be used to help identify the potential benefits of transmission investments. We recommend policy makers and planners use this checklist to document, evaluate, and communicate a comprehensive "business case" for transmission projects.

- To further explain how benefit-cost analyses can be used in the planning process, Section III focuses on a proposed improvement to the current planning and cost allocation processes through a four-step framework for identifying and evaluating valuable transmission projects and their potential benefits. These four steps will be followed by a discussion of how the benefits of transmission should be analyzed in light of considerable near-term and long-term uncertainties

- Next, Section IV raises and provides solutions to several methodological challenges associated with the identification and evaluation of transmission projects. We discuss: (a) how the costs of transmission investments should be compared with the investments' benefits over the various time horizons; (b) the difference between overall benefits (often referred to as "societal" or economy-wide benefits) and electricity-customer impacts; (c) how estimates for the distribution of benefits should be used to inform cost allocation; and (d) how transmission-related benefits should be considered and analyzed in interregional planning.

- Section V then summarizes the extent to which transmission planning efforts in Regional Transmission Organizations (RTOs) and non-RTO regions have addressed and estimated various economic, reliability, public policy, and other benefits that transmission investment can provide.

- And finally, for the practitioners, Section VI provides a detailed technical discussion to document available approaches, best practices, and metrics that allow for a more comprehensive evaluation and estimation of benefits associated with transmission infrastructure investment. This section of our report is targeted to industry executives, managers, and planning staff charged with evaluating transmission investments and developing the business case for potential projects.

Transmission planning faces many other challenges today. While we are tempted to comment on all of them, this report focuses on the identification and evaluation of transmission benefits. Some of the topics that we are *not* addressing include the complexities associated with: (1) the permitting and siting of new transmission facilities; (2) the processes and available options for the allocation and recovery of transmission costs; (3) the differences between cost-of-service-regulated and market-based (or "merchant") transmission investments; (4) the differences between the transmission planning and integrated resource planning (IRP) processes of vertically-integrated utilities; (5) the detailed step-by-step and iterative transmission planning process itself, including the comparisons of different transmission options and non-transmission alternatives and how one selects the most valuable projects and configurations; (6) the development of decision-analysis tools or frameworks that may be able to streamline the planning decision based on comprehensive analyses of transmission and non-transmission investment options; (7) the institutional and organizational barriers to creating a credible, unbiased, and comprehensive planning process; (8) the implications of setting different allowed rates of return on transmission investments and regulatory incentives for such investments; and (9) the broader political economy associated with building transmission, cost allocation, permitting, and regulation.

Even though these topics are not directly addressed in this report, we feel that the main topic—identifying, understanding, and evaluating transmission-related benefits—is a critical component of transmission planning and therefore serves as a foundation upon which these other topics can be addressed. It is our overarching recommendation that policy makers and planners consider the full set of potential benefits in all planning efforts going forward. To support this recommendation, we also suggest supplementing existing planning processes with a four-step framework under which the broad set of benefits would first be identified and then analyzed for public interest determinations.

B. Benefits of Transmission Investments and Their Relevance to Industry Planning and Cost Allocations

Traditionally, the majority of transmission projects have been proposed and developed by vertically-integrated incumbent utilities whose primary focus is to serve native load and maintain a reliable transmission system for their franchised service areas. Over time, the bulk power grid has become highly integrated regionally and will become even more so in the future with the implementation of the Federal Energy Regulatory Commission's (FERC's) Order No. 1000, which requires that both RTO and non-RTO regions consider reliability, economic, and public policy drivers in their regional and interregional transmission planning processes.

In the last decade, the most visible trend away from the traditional approach to planning has occurred in RTOs that operate organized markets. In those regions, transmission planning has gradually expanded beyond addressing reliability and load serving concerns to include economic and public-policy drivers. In that context, planners and regulators increasingly recognize that planning for economic- and public-policy-driven transmission projects requires consideration of the wide range of benefits and costs associated with these investments. Non-transmission alternatives also need to be considered, which means the transmission benefits must be weighed against the benefits associated with those alternatives as well. To the extent that this trend is also occurring in non-RTO regions, it seems less apparent primarily because the evaluation of at least some of the economic or public-policy benefits of transmission expansion is incorporated within the utilities' state-regulated integrated resource planning.

In RTO regions where planning involves multiple utility transmission owners within a single organized market, economic analyses have become more integral to the transmission planning process. Some RTOs—such as the PJM Interconnection (PJM), the New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), and the Energy Reliability Council of Texas (ERCOT)—rely primarily on the traditional application of production cost simulations to determine whether the economic value of building a transmission project outweighs its costs. Other regional system operators—in particular the Midwest Independent System Operator (MISO), the Southwest Power Pool (SPP), and the California Independent System Operator (CAISO)—have expanded the scope of analyzing economic transmission projects to consider an increasingly broader range of benefits, including reduced system losses, increased system reliability, access to lower-cost renewable generation, and increased market competition. In non-RTO regions—such as the Southeastern U.S. and ColumbiaGrid—individual utilities identify their local transmission needs through their transmission and integrated resource planning efforts. The regional plans are then based on an aggregation of the local projects of individual utilities and an assessment of whether larger regional projects would provide more cost-effective solutions to the aggregated local needs.

Despite the differences among regions in how they consider transmission benefits in planning, the same set of potential transmission benefits applies regardless of the specific market or geographic location. The magnitudes of benefits associated with transmission investments depend on the market conditions and the physics of electric power flows, and not on the regulatory framework under which the investments are made.

Recent developments in transmission planning around the country show that the industry and regulators have reached a point where a more comprehensive and standardized catalogue of benefits and methodologies for estimating benefits should be articulated and considered. Based on the industry experience and our own, we have assembled a comprehensive list of potential economic benefits that transmission investments can provide (in Table ES-1). In addition to production cost savings as traditionally estimated in the industry, the table lists eight categories of additional economic benefits that often are not estimated or overlooked. We address each of these potential benefits, explain why they often have not been captured in the traditional metrics, and present examples of instances where these benefits have been already analyzed and used to guide transmission investment decisions. A solid understanding and appreciation of the full range of costs and benefits will help avoid making premature decisions about valuable projects whose wide spectrum of benefits relative to proposed alternatives might be overlooked. Assembling this experience will hopefully provide a common understanding of the range of potential transmission benefits, inform the planning processes that different regions are developing in compliance with Order 1000, and guide planners and policy makers in making transmission investment decisions across different regions going forward.

Above all else, we recommend that the catalogue of benefits in Table ES-1 be used as a "checklist" during initial transmission project conceptualization efforts to help planners identify a comprehensive inventory of the projects' potential costs and benefits. Starting with an inventory of possible transmission benefits during the initial project conceptualization effort would help avoid limiting the scope of benefits considered to those for which analytical tools are readily available or only to those that have been evaluated traditionally.

As we discuss in Section V of this report, all of these benefits have been considered by some planning entities for at least some transmission projects. Some of these benefits can be measured readily through standard benefit metrics while others may be unique to specific transmission projects and require additional analyses. Examples of the approaches and tools utilized to estimate these benefits are discussed in Section VI of our report.

C. Use of Benefits Metrics: Recommended Approaches for Planning

In addition to the advantages of starting project evaluations with a comprehensive list of potential costs and benefits, we also offer the following suggestions to planners and policy makers when evaluating the merits of transmission projects:

- *Consider all Benefits*. Production cost simulations have become a standard tool for many transmission planners, and such a shift represents a significant progress in evaluating the economic benefits of transmission. However, the results only provide estimates of the short-term dispatch-cost savings under a singular set of generally simplified system conditions. Traditionally, these simplified simulations yield benefit estimates that reflect just a portion of total production cost savings and an even smaller portion of the overall economy-wide benefits provided by transmission investments. Other important benefits are often more difficult to estimate and are often overlooked. While not all proposed transmission projects can (or should) be justified economically, overlooking benefits because the traditional tools do not automatically capture these benefits often leads to the rejection of otherwise desirable projects. Benefits that are potentially significant but difficult to estimate should be analyzed by calculating their likely range and magnitude. Omitting consideration of such difficult-to-estimate benefits inherently assigns a zero value and thereby results in an understatement of total project benefits. Some benefits are long-term in nature and others materialize immediately. Some are policy-driven or policy-dependent, necessitating a clear understanding of the goals policy makers are trying to achieve. The long-term benefits of a physical asset with a useful life of at least 40 years should be considered as well—they are tangible and attainable even if they are difficult to estimate given the long time horizon.

Table ES-1
Potential Benefits of Transmission Investments

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
1a-1i. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
	i. More realistic representation of system utilization in "Day-1" markets
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or c. Reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	c. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

- *Define the Scope of Transmission Benefits and the Perspective Taken.* The process for identifying transmission benefits is often limited to the impacts of new projects on customer rates within a utility's system or a planning region. Such perspective is important because those who pay for the transmission facilities should also obtain benefits that are "commensurate" with their share of costs. However, a benefit analysis limited to the direct rate impact on customers, especially customers in a single utility footprint or in the planning region, could miss benefits to a region or a larger portion of the economy. Overly narrow benefits evaluations of economic or public policy-driven projects can also miss increased customer value from improved reliability and ignore benefits that accrue to other market participants or regions. In some cases, applying an electricity-customer perspective can overstate benefits relative to true efficiency gains by ignoring costs imposed on other market participants or regions. To avoid under- or overstating the total benefits of transmission investments, we recommend that benefit-cost analyses of transmission projects be derived from a perspective that considers the overall benefits (often referred to as "societal" or economy-wide benefits) that accrue to a broad range of market participants and the economy as a whole.

- *Understand Total Benefits Prior to Cost Allocation.* Understanding the overall project benefits prior to making cost allocation decisions will enable participants in the planning process to identify those projects that are most beneficial in the long run from an economy-wide perspective. How the distribution of the identified benefits is estimated to accrue to regions, areas, and market participants will ultimately drive both regional and interregional cost allocation—but cost allocation should be addressed only *after* the overall benefits of transmission projects have been considered for inclusion in regional plans. Addressing cost allocation too early in the planning process or strictly on a project-by-project basis can create strong incentives for some market participants and policy makers to understate benefits during the planning and project evaluation process in an effort to reduce their cost responsibility for a project. This can result in the rejection of even very valuable projects. Aggregating beneficial transmission projects into larger portfolios of projects can simplify the necessary cost allocation analyses, reduce misperceptions that benefits appear to accrue only to a limited subset of market participants, and thus facilitate cost allocation.

- *Consider All Regional Benefits in Interregional Planning.* Interregional transmission planning and cost allocation is especially challenging given the tendency of neighboring regions to evaluate interregional projects based only on the subset of benefits that are common to the planning processes of each of the respective regions involved. Focusing only on common benefits results in the consideration of a narrower set of benefits in interregional projects than are considered for region-internal projects. To avoid this "least common denominator" outcome in interregional planning, we recommend that neighboring regions evaluate interregional projects in light of the full set of potential benefits that are considered for regional projects in each region. This approach would help planners and policy makers to better understand the full benefits of interregional projects to their planning region and to make decisions that are more efficient from an interregional perspective and well-aligned with the interest of all affected regions. Without an inclusive recognition of all potential benefits by each of the neighboring regions, coordinated interregional planning in compliance with FERC Order No. 1000 would not be able to identify and ensure the development of many projects that benefit two or more regions.

- *Address Uncertainties.* The industry faces considerable uncertainties on both a near- and long-term basis that should be considered in transmission planning. The consideration of near-term uncertainties—such as uncertainties in loads, volatility in fuel prices, and transmission and generation outages—is important because the value of the transmission infrastructure is generally disproportionately concentrated in periods of more challenging, or possibly extreme, market conditions. The consideration of long-term uncertainties—such as industry structure, new technologies, fundamental policy changes, and other shifts in market fundamentals—is important for developing robust transmission plans and investment strategies, valuing future investment options, and identifying "least-regrets" projects. We recommend a more comprehensive planning approach that includes: (1) evaluating long-term uncertainties through scenario-based analyses; and (2) evaluating near-term uncertainties within scenarios through sensitivity or "probabilistic" analyses.

- *Consider Long-Term Benefits.* Several methods exist for comparing benefits and costs in the transmission planning processes. The methods currently used by planners and regulators differ by the number of years analyzed (*i.e.*, planning horizons), how benefits are estimated over the short-term and long-term, whether levelized or present values are used in the benefit and cost estimations, and the benefit-to-cost threshold that projects must clear. After analyzing the various methods currently employed in different planning regions, we recommend that the estimated benefits be compared with estimated project costs—either on a present value or levelized annual basis—over a time period, such as 40 or 50 years, that approaches the useful life of the physical assets. Paying attention to how benefits and costs accrue over time and across future scenarios will also help planners to optimize the timing of transmission investments from a long-term value perspective.

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Appendix: Checklist of Economic Benefits of Transmission Projects

I. INTRODUCTION AND BACKGROUND

The purpose of this study is three-fold. First, WIRES, also known as the **W**orking Group for **I**nvestment in **R**eliable and **E**conomic Electric **S**ystems, has asked *The Brattle Group* to document the broad range of potential transmission-related benefits and how they can be identified and estimated for specific transmission investments. Second, we document and discuss the experiences of regional transmission organizations (RTOs) and non-RTO regions in analyzing the economic, reliability, public policy, and other benefits that new or upgraded transmission can provide. Third, based on the collective experience documented, we catalogue the range of potential benefits offered by transmission investments and summarize the experience with the estimation of these benefits. Put together, the transmission-related potential benefits, metrics, and estimation practices documented in this report can be applied to evaluate any individual or group of transmission investments.

Traditionally, the majority of transmission projects have been proposed and developed by vertically-integrated utilities whose primary focus is to serve native load and maintain a reliable transmission system within their franchised service areas. For the most part, maintaining a system that meets all applicable reliability standards has been the main driver of transmission planning over the last several decades,[1] as transmission additions are often necessary to address load-serving needs, generation interconnection requests, and new transmission service requests. To ensure that system reliability is maintained, utilities and transmission planning organizations conduct engineering studies and identify the most cost-effective system upgrades to address the identified reliability needs.

In the last decade, the focus of transmission planning has gradually expanded beyond addressing reliability concerns to include “economic” (also referred to as “market efficiency”) and public-policy drivers for transmission investments. New Federal Energy Regulatory Commission (FERC) requirements for allocating costs roughly commensurate with benefits have also brought additional attention to the identification and analysis of transmission benefits. As a result, understanding the benefits of transmission projects and comparing these benefits to project costs has become increasingly important. This type of benefit-cost analysis has also attracted the attention of policy makers and transmission customers, who ultimately have to pay for the costs of the new facilities.

In response to the evolving need to consider transmission investment drivers beyond reliability requirements, transmission companies and RTOs have developed new processes for evaluating economic or market-efficiency projects. Similar to reliability-driven planning processes, many of the evaluation methodologies for economic projects were specified in a formulaic fashion.

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1 Reliability violations set a standard for maintaining a secure supply of electricity to all consumers. There are currently in place well-established processes for reliability-driven transmission planning that requires engineering analyses based on well-defined cases to first identify and then address reliability violations, such as the so-called “N-1” criteria violations, as determined by the North American Electric Reliability Council (NERC). These reliability standards provide clear criteria, which led to the development of well-honed formulaic evaluation processes that use established analytical tools (such as power flow models) to identify future reliability violations and how to avoid these violations through transmission upgrades or non-transmission alternatives. (NERC Reliability Standards, 2013)

These formulaic methods often narrowly relied on simplified production cost analyses to measure economic benefits. The unintended consequence of these narrow, formulaic approaches is that few (if any) economic transmission projects could ever meet the specified thresholds and planning criteria because the simplified production cost analyses do not measure all of the potential benefits associated with transmission projects, and, therefore many beneficial projects may not be developed.

The simplified production cost analyses do not easily to help planners assess the value of transmission needed due to public policy drivers. Thus, a few RTOs and other transmission planners have recognized that planning for economic and public-policy driven projects requires a broader perspective that recognizes multiple transmission-related benefits. However, there is no industry standard for the consideration of a broad set of transmission-related benefits in the planning process. Consequently, we intend, through this report, to address this gap and develop approaches that can be used as a standard to identify, document, and evaluate a broader range of transmission-related benefits and communicate a more comprehensive "business case" for transmission projects. In doing so, we identify approaches and best practices that allow for a more complete evaluation and estimation of benefits associated with transmission infrastructure investment.

The remainder of this report is organized as follows. **Section I** provides background, including the purpose and scope of our report. For the benefit of both policy makers and practitioners, **Section II** discusses the importance of accounting for transmission benefits in the context of the planning process and then summarizes the types of benefits transmission projects may offer. Compiled from a detailed review of industry practices and our own experience, we then present a "checklist of economic benefits" that can be used to help identify the potential benefits of transmission investments. We recommend policy makers and planners use this checklist to document, evaluate, and communicate a comprehensive "business case" for transmission projects.

To explain further how benefit-cost analyses can be used in the planning process, **Section III** focuses on a proposed improvement to the current planning and cost allocation processes through a four-step framework for identifying and evaluating valuable transmission projects and their potential benefits. The four steps will be followed by a discussion of how the benefits of transmission should be analyzed in light of the considerable near-term and long-term uncertainties. Next, **Section IV** raises and provides solutions to several methodological challenges associated with the identification and evaluation of transmission projects. We discuss: (a) how the costs of transmission investments should be compared with the investments' benefits over the various time horizons; (b) the difference between overall benefits (often referred to "societal" or economy-wide benefits) and electricity-customer impacts; (c) how estimates for the distribution of benefits should be used to inform cost allocation; and (d) how transmission-related benefits should be considered and analyzed in interregional planning;.

Section V then summarizes the extent to which transmission planning efforts in RTOs and non-RTO regions have addressed and quantified various economic, reliability, public policy, and other benefits that transmission investment can provide. And finally, for the benefit of practitioners, **Section VI** provides a detailed technical discussion to document the available approaches, best practices, and metrics that allow for a more comprehensive evaluation and estimation of benefits associated with transmission infrastructure investment. This section of our report is targeted to industry executives, managers, and planning staff charged with evaluating transmission investments, performing the necessary analyses, and developing the business case for potential projects.

Transmission planning faces many other challenges today. However, while we are tempted to comment on all of them, this report focuses on the identification and evaluation of transmission benefits. Some of the **topics we are *not* addressing** include the challenges associated with: (1) the permitting and siting of new transmission facilities; (2) the processes and available options for the allocation and recovery of transmission costs; (3) the differences between cost-of-service-regulated and market-based (or "merchant") transmission investments; (4) the differences between transmission planning and integrated resource planning (IRP) processes of vertically-integrated utilities; (5) the detailed step-by-step and iterative transmission planning process itself, including the comparisons of different transmission options and non-transmission alternatives and how one selects the most valuable projects and configurations; (6) the development of decision-analysis tools or frameworks that may be able to streamline the planning decision based on comprehensive analyses of transmission and non-transmission investment options; (7) the institutional and organizational barriers to creating a credible, unbiased, and comprehensive planning process; (8) the implications of setting different allowed rates of return on transmission investments and regulatory incentives for such investments; and (9) the broader political economy associated with building transmission, cost allocation, permitting, and regulation.

Even though these topics are not directly addressed in this report, we feel that its main topic—identifying, understanding, and evaluating transmission-related benefits—is a critical component of transmission planning and therefore serves as a foundation upon which these other topics can be addressed. It is our overarching recommendation that policy makers and planners consider the full set of potential benefits in all planning efforts going forward. To support this recommendation, we also suggest supplementing existing planning processes with a four-step framework under which the broad set of benefits would first be identified and then be analyzed for public interest determinations.

II. TYPES OF TRANSMISSION-RELATED BENEFITS

This section of our report first discusses the importance of accounting for transmission benefits in the context of the planning process and then summarizes the types of benefits transmission projects may offer. We then present a "checklist of economic benefits" that is based on our review of industry practices as presented in Section IV and our own experience. As we discuss in Section III, this checklist can be used to help identify the potential benefits of transmission investments that would be useful for communicating a comprehensive "business case" for transmission projects.

As is at least conceptually understood, transmission investments can support a wide range of benefits. The most common benefits include increased reliability, decreased transmission congestion, renewables integration, reduced losses, reduced resource adequacy requirements, and increased competition in power markets. Some of these benefits spread across wide geographic regions and multiple utility service areas and states, and can significantly affect market participants ranging from generators to retail electricity customers. Over the long-life of the transmission assets, the nature and the magnitude of the benefits can also change significantly. For example, benefits associated with today's transmission grid, such as the ability to operate competitive wholesale electricity markets, could hardly have been imagined or estimated when the facilities were built four or five decades ago, long before the advent of open access to the transmission grid.

Recent transmission planning experiences have also shown that the scope of transmission-related benefits generally extends beyond the main driver of a particular project. While many transmission investments are motivated by a single driver—such as reliability, congestion relief, or renewable generation integration—the benefits of these transmission investments generally extend beyond the individual driver. For example, many reliability-driven projects also will reduce congestion and support the integration of renewable generation. Similarly, a transmission project driven by congestion-relief objectives also will also increase system reliability, help to avoid or delay reliability projects that would otherwise be needed in the future, or reduce system-wide investment needs by allowing access to lower-cost generation resources. This multi-purpose, multi-value aspect of transmission investments requires a more systematic analysis of the wide range of transmission-related benefits and the interaction of transmission investments with other system-wide costs and non-transmission investments.

A. Production Cost Savings as a Traditional Benefit Metric

The most commonly-considered economic benefits of transmission investments are estimated reductions in simulated fuel and other variable operating costs of power generation (generally referred to as production cost savings) and the impact on wholesale electricity market prices (in many cases referred to as locational marginal prices or LMPs) at load-serving locations of the grid. These production cost savings and load LMP benefits are typically estimated with production cost models that—in attempts to streamline the modeling effort—are configured to simulate generation dispatch and transmission congestion based on simplified approximations of power flows, predefined transmission constraints, and normalized system conditions.

In a recent assessment of RTO performance by FERC, the majority of RTOs cited congestion relief as a main benefit from expanding transmission capacity. For example, PJM noted that market simulations of recently-approved high-voltage upgrades indicate that these upgrades will reduce congestion charges by approximately $1.7 billion compared to congestion charges without the upgrades.[2] While changes in total congestion charges are informative, the economic value of such congestion relief is generally reflected in production cost savings (from an economy-wide perspective) and load LMP benefits (from the perspective of customers in restructured retail electricity markets) because a reduction in congestion typically increases the use of more efficient (lower cost) generators over inefficient (higher cost) ones.

[2] FERC Performance Metrics, 2011, Appendix H: PJM, p. 275. Additionally, an 82% reduction in annual congestion costs is forecast from $980 million "as is" 2012 baseline to $173 million "as planned" based on PJM's 2016 RTEP (Cash, 2013).

Since production cost simulations have become a standard tool for many transmission developers and grid operators, production cost savings estimation is the analysis that can be repeated for all proposed transmission projects or groups of projects. While production cost savings are readily estimated (based on simplified assumptions), the results only provide estimates of the short-term dispatch-cost savings of system operations. These savings are only a portion of the overall economic benefits provided by transmission investments and do not capture a wide range of other transmission-related benefits, including many long-term capital and operational cost savings. For example, as a Western Electric Coordinating Council (WECC) planning group recognized:

> The real societal [*i.e.*, overall economic] benefit from adding transmission capacity comes in the form of enhanced reliability, reduced market power, decreases in system capital and variable operating costs and changes in total demand. The benefits associated with reliability, capital costs, market power and demand are not included in this [type of production cost simulation] analysis.[3]

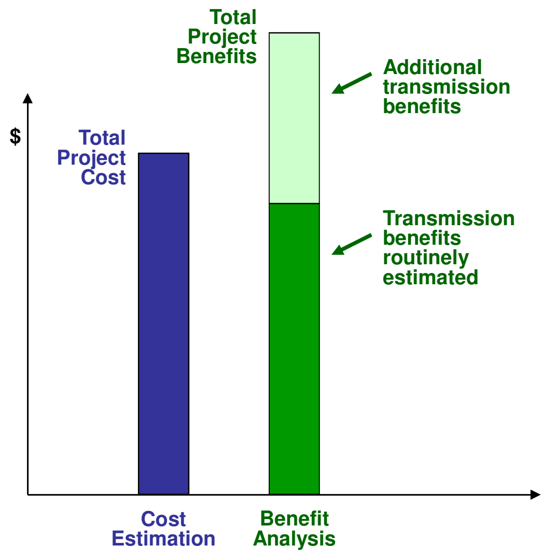
In addition, as we explain in more detail later in Section VI, production cost simulations as traditionally undertaken are based on a number of simplified assumptions that can significantly understate the derived estimates of production cost savings.

B. Examples of a More Fully Articulated Set of Transmission Benefits

Aside from production cost savings, other benefits—particularly those associated with improved reliability, reduced generation capital costs, reduced market power and demand—are often omitted in many transmission benefit-cost analyses. These omitted benefits are sometimes inaccurately viewed as "soft" or "intangible" benefits simply because they are not yet routinely estimated by transmission owners and system operators. Even though some of these additional benefits can be difficult to estimate in certain situations, omitting them effectively assumes these benefits are zero, which may not be the case. Instead, estimating the approximate range of likely benefits will yield a more accurate benefit-cost analysis and provide more insightful comparisons that avoid rejecting beneficial transmission investments. For example, transmission lines can increase competition in wholesale electricity markets as more generators gain access to a wider set of customers. In some cases, transmission upgrades can reduce a region's resource adequacy needs and offer access to lower-cost generating resources. While estimates of resource adequacy or competitive benefits might not be precise at times, rough estimates of the likely magnitude of these benefits can generally be developed. As conceptually illustrated in Figure 1, overlooking or ignoring such difficult-to-quantify or not-commonly-estimated benefits can lead to rejection of otherwise desirable projects.

3 SSG-WI Transmission Report, October 2003.

Figure 1



As we noted in a prior report for WIRES,[4] the post-construction assessment of the Arrowhead-Weston transmission line in Wisconsin, developed by American Transmission Company (ATC) in 2008, provides a good example of the broad range of benefits associated with that project. The primary driver of the Arrowhead-Weston line was to increase reliability in northwestern and central Wisconsin by adding another high voltage transmission line in what the federal government designated at the time as "the second-most constrained transmission system interface in the country."[5] The project addressed this **reliability** issue by adding 600 MW of carrying capacity and improving voltage support, the impact of which was noticeable in both Wisconsin and in southeastern Minnesota. By also **reducing congestion**, ATC estimated that the line allowed Wisconsin utilities to decrease their power purchase costs by $5.1 million annually, saving $94 million in net present value terms over the ensuing 40 years. Similarly, ATC estimated that the project saved $1.2 million in **reduced costs for scheduled maintenance**. The high voltage of the line (345 kV) also **reduced on-peak energy losses** on the system by 35 MW, which **reduced new generation investments** equivalent to a 40 MW power plant. The reduced losses also avoid generating 5.7 million MWh of electricity that would **reduce CO_2 emissions** by 5.3 million tons over the initial 40-year life of the facility. In addition, the transmission line has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to **help Wisconsin meet its RPS requirements**. The construction of the line **supported 2,560 jobs**, generated $9.5 million in **tax revenue**, created $464 million in total **economic stimulus**, and will provide $62 million of **income to local communities** over the next 40 years. The increased reliability of the electric system has provided **economic development benefits** by improving the operations of existing commercial and industrial customers and attracting new customers. Lastly, the project also provided **insurance value against extreme market conditions** as was illustrated in a North American Electric Reliability Corporation (NERC) report which noted that if the Arrowhead-

4 Pfeifenberger and Hou, 2011, Section IV.

5 ATC (2009), p. 7.

Weston line had been in service earlier, it would have **averted blackouts** in the region which impacted an area that stretched from Wisconsin and Minnesota to western Ontario and Saskatchewan, affecting hundreds of thousands of customers.

Figure 2 and Figure 3 summarize examples of transmission benefit-cost analyses that identified and estimated a number of the transmission-related benefits discussed above. As shown, the examples show projects that provide benefits significantly in excess of transmission-related rate increases, with the estimated economic benefits exceeding their costs by 60% to 70%. These examples also show that the traditionally estimated production cost savings are only a portion of the total benefits.

A comprehensive analysis of a broad range of transmission-related benefits also may show that some benefits have negative values (*i.e.*, representing costs). For example, transmission investments that help integrate lower-cost but distant generating resources can also increase system-wide transmission losses. Some transmission expansions can lead to increased emissions and associated environmental costs; or in some cases, certain transmission projects may cause larger environmental impacts in terms of their land use. From a consumer perspective, new transmission could decrease the value of existing physical or financial transmission rights (FTRs), thereby offsetting benefits related to congestion relief or the increased availability of transmission rights.[6]

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[6] The economic analysis of the Paddock-Rockdale Project is a good example of transmission benefits that could be positive or negative. We have presented in Figure 2 the summary results of one of the seven scenarios examined when ATC evaluated the project. In Figure 2, we show that additional "FTR and Congestion Benefits" added $6 million to the savings of the project. However, the results for the other Scenarios analyzed by ATC showed different patterns. Specifically, the "FTR and Congestion Benefits" was actually negative in three of the seven scenarios. In fact, it had a negative value of $117 million in one of them, which offset $379 million in production cost savings for that scenario. These results also document that benefits can vary greatly across possible different futures, which illustrates the importance of scenario analysis to evaluate the robustness of project economics as we discuss further below.

Figure 2
Total Benefits Quantified for ATC's Paddock-Rockdale Project

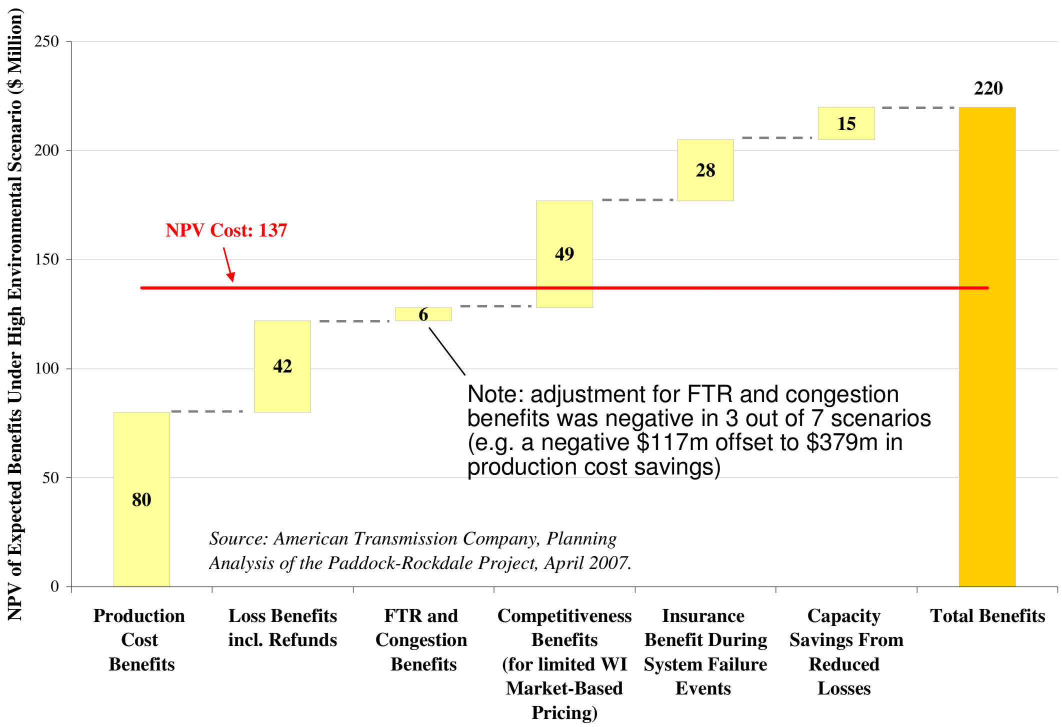
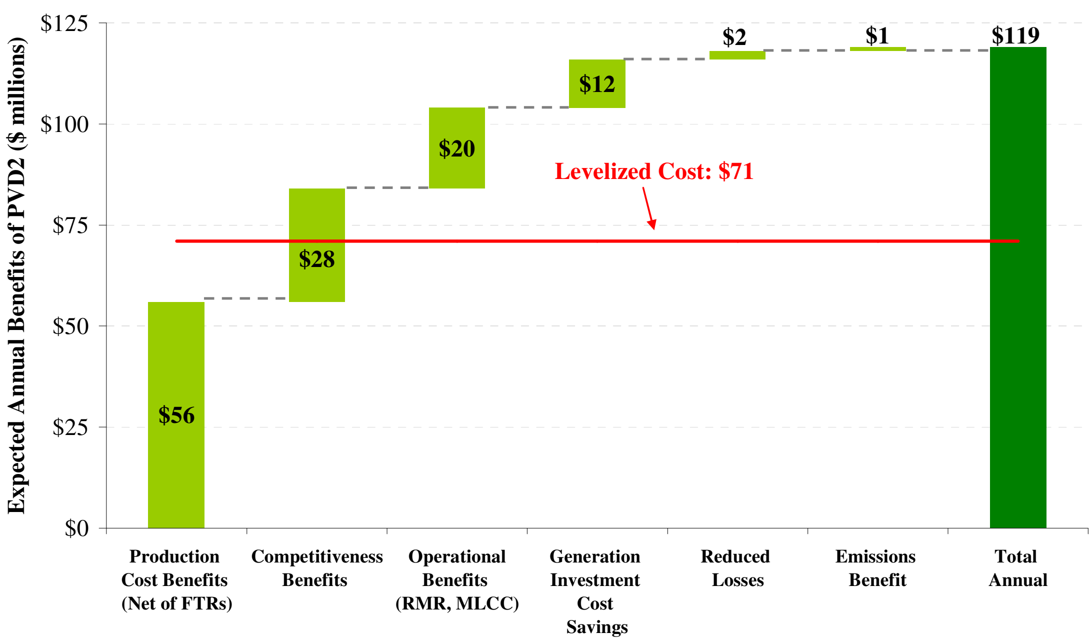


Figure 3
Total Benefits Quantified for Southern California Edison's Palo Verde-Devers 2 Project



Source: California ISO (CAISO), *Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2),* February 24, 2005.

C. A "CHECKLIST" OF POTENTIAL ECONOMIC BENEFITS OF TRANSMISSION INVESTMENTS

Recent developments in transmission planning around the country (summarized more systematically in Section V of this report) for both RTO and non-RTO regions show that the industry and regulators have reached a juncture where a more complete, standardized catalogue of benefits and methodologies for estimating benefits can be articulated. Based on this industry experience and our own experience of working with transmission developers and RTOs, we assembled a comprehensive catalogue of potential economic benefits that transmission investments can provide. This "checklist of economic benefits" is summarized in Table 1 and presented in more detail in Appendix A. It shows the production cost savings traditionally estimated as well as additional categories of benefits that often are not evaluated or even considered. Section VI provides a more technical discussion of the metrics and experience with analytical techniques that can be applied to estimate the value of these benefits.

This more comprehensive catalogue of transmission-related benefits reflects that the magnitude of the economic benefits of transmission investments depends on the market conditions and the physics of electric power flows. It does not depend on how stakeholders can agree voluntarily on which benefits count and which do not. For example, just because a certain subset of transmission-related benefits, such as congestion relief, might not be *considered* in a particular region's current planning processes, it does not mean that transmission investments would not reduce congestion and associated production costs. While regional differences may have significant impacts on the type of benefits that would likely materialize, these regional differences will mostly affect the magnitude of the benefits but not their existence.[7] We consequently recommend that these benefits be considered for all proposed transmission projects to assess if they provide significant value, and if so, be evaluated further to estimate their magnitudes. It is important to recognize, however, that individual transmission projects will not yield all of these benefits and may not found to be cost-effective even if all benefits are considered.

In the next section, Section III, we provide suggestions on how these benefits metrics can be incorporated in transmission planning (or resource planning) processes.

7 For example, the value of the storm-hardening benefits of a new transmission project may be substantially less in regions with few severe storms.

Table 1
Potential Benefits of Transmission Investments

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
1a-1i. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
	i. More realistic representation of system utilization in "Day-1" markets
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or c. Reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	c. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

III. INCORPORATING ECONOMIC BENEFITS IN THE TRANSMISSION PLANNING PROCESS

Utilizing an expanded list of transmission-related benefits in the planning process raises several methodological challenges, including when and how the benefits can be identified and evaluated. In this section, we address some of these challenges at a high level. We first propose to augment current planning and cost allocation processes through a four-step procedural framework. Then we discuss how the benefits of transmission should be analyzed in light of considerable near-term and long-term uncertainties.

A. A Framework to Facilitate Identifying and Considering Transmission Projects and Their Benefits

First and foremost, the transmission planning process and the considerations for transmission-related benefits go hand in hand. The choice of what projects to pursue is directly linked to how planners and developers view the need for transmission projects and, thereby, the potential benefits that these projects would provide. Through our experience, we have found that a successful approach to the identification of potentially beneficial projects is to consider all the potential benefits offered by the contemplated transmission investments at the outset, when assessing the need of certain projects. Putting all the benefits on the table upfront helps avoid encumbering the overall planning process by focusing too early on time-consuming market simulations. Also recognizing that cost allocation debates can sometimes get in the way of developing innovative transmission projects that offer benefits to a wide range of market participants and service areas, as discussed further below, we present a simple four-step process that begins with project identification using the checklist of potential economic benefits.

(1) The first step in our recommended framework is to bring together system planners, project developers, and other stakeholders **to identify potential transmission projects that could supplement or replace baseline reliability projects and to develop a comprehensive list of their likely benefits**. Such "brainstorming" sessions would be most effective when facilitated by independent, unbiased planning professionals such as RTO staff. They may also need to involve market participants to help inform assumptions about existing and anticipated system conditions. The participants would propose and document project ideas while simultaneously describing anticipated benefits. The goal of this step is to identify a wide range of possible projects that could address reliability needs, meet public policy objectives, and offer economic benefits without impeding or limiting the scope of options and benefits considered at the outset. This step is also used to gather an inventory (and possibly ranking) of promising transmission projects and their likely costs and benefits with no screening of projects based on how readily benefits could be estimated or how costs might allocated. This screening can be done at a later stage after more analyses have been conducted. Only two questions should be asked at this stage of the process: (a) What transmission projects would likely be beneficial in addition to or instead of those that have been identified to meet reliability standards?; and (b) What are the likely types of benefits that these projects would offer and why are they expected to be significant?

(2) The second step of this framework is to perform an unbiased evaluation of the proposed projects from both a reliability and economic perspective and to **estimate the value of as many of the identified benefits as practical** without regard to how the benefits would be distributed across the region, to neighboring regions, or to different groups of transmission customers, generators, or other market participants. Some of the economic benefits can be measured readily through traditional benefit metrics, such as "Adjusted Production Cost" or "APC" savings. These traditional benefit metrics would be analyzed for every project or portfolio of projects through simulations and pre-specified formulaic calculations that can be undertaken routinely within each planning cycle. Other benefits may not lend themselves to routine analyses through formulaic benefit metrics. The value of those benefits would be estimated when the anticipated magnitude is significant such that it could materially affect the attractiveness of the proposed projects. Benefits that could be significant but are more difficult to estimate should be analyzed by estimating at least their likely range and magnitudes—rather than implicitly assuming that they have zero value because their precise values are difficult to calculate. Benefits that are unique to specific projects could be assessed only if and when they are applicable.

(3) The third step is to **determine whether the proposed transmission investments would be beneficial overall** by comparing the magnitude of estimated economy-wide (often referred to as "societal") benefits with estimates of the total costs of the projects.[8] Once the overall value of benefits has been estimated, a benefit/cost ratio can be calculated and compared to the applicable threshold to determine whether a project or portfolio of projects is worth pursuing. This is also the step where non-transmission alternatives should be considered when comparing benefits and costs of proposed projects. We have found that, while it is intuitive to estimate the economic benefits associated with every proposed transmission project, often several projects could be considered jointly because the combination of the projects can provide higher (or in some cases lower) benefits than the sum of each project's individual benefits. By analogy, a particular section of the interstate highway system would have little value unless it is integrated with the rest of the system. Likewise, a group of transmission facilities that serve as a regional overlay may provide substantially greater regional benefits (*e.g.*, in the form of reliability, congestion relief, emissions reduction, advanced load serving capability, *etc.*) than the sum of the benefits for each individual segment that makes up the regional overlay. Competing or conflicting projects would need to be evaluated independently. Such distinction reinforces the need to describe and understand the potential benefits of each project upfront before delving into the quantitative analyses. If a group of facilities can offer more benefits jointly than independently, developing efficient portfolios of

[8] This approach is consistent with Principle No. 3 ("The appropriate standard of measurement of the benefits of transmission is aggregate societal benefits within the geographic region being examined") in the whitepaper by the Blue Ribbon Panel (Baldick, *et al.,* 2007). We add, however, that (consistent with Principle 4A of the same whitepaper) the "geographic region being examined" should not necessarily be limited to a single planning region, but be large enough to include all planning regions that are anticipated to see significant benefits from a proposed project (or group of projects).

transmission projects would require iterative analyses of several transmission options and non-transmission alternatives in this step.

(4) The fourth step is to **address cost allocation**. It is important to address cost allocation only after transmission projects have been found to be beneficial overall. Estimates of the distribution of the identified benefits can then be used to inform cost allocation. In this step, through facilitation by an unbiased planning entity, an allocation of costs should be achieved that is commensurate with the benefits received. Again, for this effort, aggregating beneficial transmission projects across a region into a portfolio of projects is advisable before determining cost allocations because a larger portfolio of transmission projects that is distributed throughout the evaluated region will tend to offer benefits that are distributed more evenly as well. We have also found that, since it is generally more contentious and difficult to estimate the distribution of benefits than to estimate the overall magnitude of the benefits, aggregating transmission projects into larger portfolios of projects will often simplify the necessary analyses, reduce any misperception that benefits appear to accrue only to a subset of market participants, and thereby help facilitate cost allocations. Addressing cost allocation too early in the planning process or strictly on a project-by-project basis can create strong incentives for some market participants and policy makers to understate benefits during the planning and project evaluation process in an effort to reduce their cost responsibility for a project. This can result in the premature rejection of even very valuable projects.

Since each system already has an existing planning process in place, we suggest system planners integrate the above framework with existing planning processes to help facilitate efficient development of transmission options and non-transmission alternatives and select the most valuable projects and configurations.

We recognize that the development of reasonably "optimal" transmission expansion plans is a challenging, iterative process. To improve the efficiency and robustness of this planning process, analytical tools that can simultaneously evaluate a wider range of transmission-related benefits under uncertain future market conditions and more integrated decision-analytical frameworks will need to be developed.[9]

B. CONSIDERING UNCERTAINTY

The economic analysis associated with evaluating new transmission investments often is limited to the evaluation of the projects under a single forecast of future market conditions. A common practice in evaluating transmission projects involves using a "Base Case" scenario that represents the planners' best guess of future market conditions or a continuation of the most recent market condition, without accounting for any potentially very large divergences in future outcomes over the long term. While the Base Case scenario provides one "vision" of the world for which the

[9] We address tools and frameworks available to evaluate a broader range of transmission benefits in Section VI of this report. For evolving analytical tools and decision-analytical frameworks—particularly with respect to planning transmission in the context of integrating renewable generation—see Munoz, *et al.*, 2013; Van Der Weijde and Hobbs, 2012; and Park and Baldick, 2013.

future value of transmission investments can be estimated, using one "Base Case" scenario could ultimately lead to over or under estimating the projects' value.

In some cases, planners may shy away from making investment decisions fearing that uncertain futures could dramatically change the value of those investments and result in regrets. However, shying away from making investment decisions because of difficulties in predicting the future could lead to a perpetual focus on small incremental transmission upgrades that address only the most urgent near-term needs, such as reliability violations, and thereby forego opportunities to capture higher values by making investments that address longer-term needs more effectively. To address this challenge, we recommend a more comprehensive planning approach that includes: (1) evaluating long-term uncertainties through scenario-based analyses and decision-analytical frameworks; and (2) evaluating near-term uncertainties through sensitivity analyses or "probabilistic" approaches.[10]

Evaluating long-term uncertainties through various future scenarios is important given the long useful life of new transmission facilities that can exceed four or five decades. Long-term uncertainties around fuel price trends, locations and size of future load and generation patterns, economic and public policy-driven changes to future market rules or industry structure, and technological changes that can substantially affect the need and size of future transmission projects are best analyzed through scenario-based analyses. The results can be used to: (1) identify "least-regrets" projects whose value would be robust across most futures; and (2) identify or evaluate possible project modifications (such as building a single circuit line on double circuit towers) to create valuable options that can be exercised in the future depending on how the industry actually evolves.

Evaluating short-term uncertainties around weather patterns, fuel-price volatilities that drive changes in generation dispatch and therefore flow patterns on the system, and generation and transmission outages can be done by specifying probabilities and correlations for key variables, importance sampling, and undertaking Monte Carlo simulations for the selected set of cases. The probability-weighted average of transmission benefits across a range of load uncertainties, fuel price fluctuations, and outage uncertainties tends to exceed the value of transmission under normalized or most likely conditions. This is because the value of transmission projects is disproportionately higher during more challenging market conditions. Thus, not analyzing the proposed projects under challenging but realistic market conditions risks underestimating their values. However, complex and time-consuming probabilistic simulations are not always necessary. Often, a limited set of sensitivity cases (*e.g.*, 90/10, 50/50, 10/90 load forecasts) with case studies (*e.g.*, simulating past extreme contingencies, outages, weather patterns) can serve as an important step toward more fully capturing the values of projects. It can also help planners better understand how these near-term uncertainties can affect the expected value of projects in any particular future year.

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10 For simplified frameworks taking into account both long-term and short-term uncertainties for transmission planning in the context of renewable generation expansion, see Munoz, *et al.*, 2013; Van Der Weijde and Hobbs, 2012; and Park and Baldick, 2013.

Several regional planning organizations have started to employ scenario and sensitivity analyses in their planning processes. For example, the Electric Reliability Council of Texas (ERCOT), the Midwest Independent System Operator (MISO), and the Southwest Power Pool (SPP) employ multiple future scenarios to evaluate transmission expansion options. The scenarios take into account (to various degrees) divergent assumptions about renewable energy additions, load levels, and a few other factors.

To address how uncertainties affect the value of transmission projects, the California Energy Commission has developed a framework for assessing the expected value of new transmission facilities under a range of uncertain variables. Their recommended approach identifies the key variables that are expected to have a significant impact on economic benefits, establishes a range of values to be analyzed for each variable, and creates cases that focus on the most relevant sets of values for further analysis, including the probabilities for each case. The variables considered in the case provided are different levels of load growth, hydro conditions, natural gas price, and generator market power.[11] Similarly, ERCOT performed simulations for normal, higher-than-normal, and lower-than-normal levels of loads and natural gas prices in its evaluation of a Houston Import Project. The ERCOT simulations showed that a $45.3 million annual consumer benefit for the base case simulation (normal load and gas prices) compared to a $52.8 million probability-weighted average of benefits for all simulated load and gas price conditions.[12]

The next section, Section IV, discusses key challenges often encountered when evaluating the costs and benefits of transmission investments in the planning process and for allocating costs.

IV. CONSIDERATIONS IN THE EVALUATION OF TRANSMISSION COSTS AND BENEFITS FOR PLANNING AND COST ALLOCATION

In this section of our report, we first discuss how to compare benefits to costs, particularly given the longevity of the investments and that the amount of benefits may change over time. Second, we discuss how transmission-related benefits should be considered in interregional planning. Third, we address the differences between overall benefits (often referred to "societal" or economy-wide benefits) and electricity-customer impacts of transmission investments. And fourth, we discuss how and when estimates for the distribution of benefits should be used to inform cost allocation.

A. COMPARING BENEFITS AND COSTS

To assess the net value and desirability of economically justified transmission investment requires a comparison of benefits and costs. Such a comparison is generally conducted by calculating a benefit-to-cost ratio. FERC Order 1000 requires that the benefit-cost threshold applied to evaluate the desirability of regional transmission projects must not exceed 1.25. In other words, if a threshold for economic projects is set by planners or regulators, FERC prohibits

11 Toolsen, 2005.

12 ERCOT, 2011, p. 10.

criteria that would require benefits to exceed costs by more than 25%.[13] While there is a FERC requirement on the threshold, there is less guidance on which benefits should be considered or how the benefits and costs should be calculated. Accordingly, practices vary considerably across regions. For example, ERCOT currently calculates benefit-cost ratios of economically-justified projects based on the revenue requirements for the first year of a transmission project's operations (*e.g.*, 5 or 10 years from today) and the benefit of the project in that same year, not taking into account any potential benefits in subsequent years. The California Independent System Operator's (CAISO's) previous evaluations of its Path 26 upgrade and Palo Verde-Devers Line No.2 (PVD-2) project compared the "levelized" annual benefits of the transmission projects to its levelized costs, both of which are levelized over the entire (*e.g.*, 50-year) economic life of the projects.[14] Most other planning processes—such as those for the New York Independent System Operator (NYISO), PJM Interconnection (PJM), Independent System Operator of New England (ISO-NE), MISO, SPP, and the process currently used by the CAISO—compare the present values of benefits to the present values of costs, with present values calculated over the first 10, 20, 40 or 50 years of an investment's useful life.[15]

To simplify the benefits estimation, planning efforts generally include analyzing the benefits for only a small number of study years, with estimates for the intermediate and outer years derived by interpolating and extrapolating from the study year results. For example, to estimate production cost savings for the next 20 to 40 years, MISO interpolated the estimated savings between three simulated years, 2021, 2026, and 2031. MISO also extrapolated the benefit trend estimated for its 2026 and 2031 simulations for another 30 years.[16] SPP's planning process for its Priority Projects estimated benefits for 40 years by simulating the systems for 2009, 2014, and 2019 and extrapolating the 2014–19 trend for another 10 years beyond 2019 before holding annual benefits constant in inflation-adjusted terms until the fortieth year.[17] Similarly, the CAISO used simulations to estimated benefits for planning years 5 and 10, but estimated benefits for the ensuing 35 to 45 years by applying a 1% real escalation rate to planning-year 10 benefits to capture the combined impacts of inflation and other factors on likely future benefits.[18]

The annual values of transmission costs are generally based on estimates of annual transmission revenue requirements (TRRs) that include the cost of depreciating the investment, a regulated return on net ratebase, taxes, and estimates of annual O&M costs. To correctly represent total costs relative to total benefits, realistic estimates of all anticipated costs should be included.

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13 This requirement that benefit-to-cost thresholds should not be higher than 1.25:1 was motivated in part by experience with planning criteria that required thresholds as high as 3:1 that essentially eliminated the feasibility of approving economically-justified transmission projects.

14 CAISO TEAM Report, 2004 and CAISO PVD2 Report, 2005.

15 The transmission planning organizations use the following time horizons to calculate benefit: NYISO 10 years; PJM 15 years; MISO 20 and 40 years; ISO-NE 10 years; SPP 40 years; and CAISO 40 years for upgrades to existing facilities and 50 years for new facilities.

16 MISO, 2011, p. 27.

17 SPP, 2010a, p. 28.

18 CAISO PVD2 Report, 2005, pp. 21–22 and CAISO Transmission Plan, 2013, p. 315.

We recommend that estimated benefits be compared—either on a present value or a levelized annual basis—to estimated project costs over a time period (such as 40 or 50 years) that at least approaches the useful life of the physical facilities. This approach is particularly important because many benefits tend to increase over time with both load growth and fuel price inflation and because the regulated revenue requirements are "front-loaded" and tend to decrease over time as the facilities are depreciated.[19] Requiring comparison of only the first year or even the first 10 years of estimated benefits with annual transmission revenue requirements for the same number of years is equivalent to raising the benefit-to-cost threshold that projects must overcome. For instance, if benefits grow with inflation over time, setting a benefit-to-cost threshold of *one* when comparing the first year of benefits (which increase with inflation) with the first year of transmission revenue requirements is mathematically equivalent to setting the benefit-to-cost threshold of approximately *two* when comparing the 40 year present value of the same stream of annual benefits and costs.

To calculate the present value of costs and benefits (or, alternatively, the "levelized" annual value of these benefits and costs) requires the selection of a discount rate. We recommend using the weighted-average cost of capital (WACC) or the allowed rate of return of the transmission owner as the discount rate for this purpose. Others have also evaluated projects using a much lower social discount rate. For example, MISO uses in its evaluation of MVPs both a 20- and 40-year NPV with two discount rates: 3% (to reflect a "societal" rate) and 8.2% (to reflect the allowed rates of return of transmission owners).[20]

Observing and analyzing the level of benefits compared to costs (in terms of the revenue requirements of the projects) on an annual basis will also be useful because that information will allow planners to optimize the timing of transmission investments. For example, the option to delay certain proposed projects until their expected annual benefits exceed estimated annual costs can increase the net present value of the investment. Similarly, it may also be possible to accelerate certain projects if earlier in-service dates would allow the project to capture additional benefits, such as avoiding transmission upgrades needed to meet reliability standards or allowing the deferral of generation investments. Such optimization will require the careful and systematic analysis of available options and alternatives, including non-transmission alternatives.

B. Overall Economic Benefits Distinguished From Benefits to Electricity Customers

Society as a whole benefits from transmission investments. While it is most relevant to examine the benefits associated with transmission investments from an economy-wide or societal perspective when making public-policy or regulatory decisions, many regulators and utilities

19 While we recognize that estimating benefits for 40 years is challenging, the approaches used by SPP, MISO, and CAISO should reasonably capture the possible range of future benefits.

20 As transmission projects are often seen as a "public good," some advocate that a social discount rate should be applied to future benefits of transmission lines as it has previously been used for "public projects in sectors such as transport, agriculture, water resources development, and land use." The recommended social discount rates generally are in the 3% to 5% range, although rates have been suggested to be as low as 0.1% for the future costs of global warming. (Budhraja *et al.*, 2008, pp. 14–19.).

tend to focus on how electricity customers (*i.e.*, "ratepayers") might benefit from the proposed transmission facilities.[21] This electricity-customer perspective is most relevant when one evaluates how much those who pay for the transmission projects would benefit from them. For instance, electricity customers are likely to benefit from production cost savings (through reduced electricity bills from cost-of-service regulated utilities), from improved reliability (which increases the value of the received service), from an increase in wholesale power market competition (even if that reduces generator profits), from reduced resource adequacy requirements or a reduction in the capacity cost of new generating resources (which reduces electricity bills), and from the avoidance or deferral of transmission or generation investments that would need to be built in the absence of the proposed transmission investment (which provides an offset to the larger transmission projects' costs).

Increased system reliability, reduced emissions, or regional economic development will benefit society as a whole, which includes electricity customers. But these benefits may not directly reduce electricity customer bills. Because benefits to electricity customers can be either a subset of total economy-wide benefits (*e.g.*, because there are benefits that do not directly accrue to electricity customers) or exceed economy-wide benefits (*e.g.*, because generators may see reduced earnings or other electric customers may see increased rates), the benefit-to-cost balance from an economy-wide perspective may differ from that of electricity customers. For example, a transmission project may offer only limited system-wide production cost savings but offer significant electricity customer benefits by reducing market prices. Alternatively, a significant portion of system-wide production cost savings may be captured by merchant generators through increased earnings, resulting in electricity customer benefits that are less than the identified production cost savings.

The existence and extent of the divergence between consumer and societal perspectives can depend on three factors: market structure, geographic scope of the study, and consideration of economy-wide benefits not reflected in electricity rates.

Market Structure. Generally speaking, the cost of power delivered to electricity customers can decrease if a transmission line allows for the dispatch of lower-cost generation or the purchase of wholesale power at lower prices. However, the extent to which electricity customers will benefit also depends on the structure of retail power markets. Under the traditional cost-of-service regulated model, electricity customers will directly benefit from: (1) reductions in the production costs of cost-of-service regulated generating plants; (2) lower-cost off-system purchases by the regulated utility; and (3) the achievement of higher off-system-sales prices for power from such regulated generating plants to offset the revenue requirement to be recovered from franchised ratepayers. In contrast, if electricity customers are served mostly through wholesale power purchases at market prices, such as in retail-access states, customers will benefit if a transmission project reduces the wholesale price of purchased power, irrespective of actual production cost

[21] Note that the academic literature generally discusses this subject matter by distinguishing between "societal benefits" (or total "welfare gains"), "consumer benefits" (or changes in "consumer surplus"), and "supplier benefits" (or changes in "supplier surplus"). We discuss these concepts in terms of overall economic (or economy-wide) benefits and electricity-customer benefits. See also Baldick, *et al.*, 2007, pp. 17-21.

savings. Reducing the cost of power to electricity customers is not automatically an economy-wide benefit because, when customers pay less for their power, a portion of those savings may be a transfer of economic gains from generators to those customers. This transfer of gains can yield a result in which the economy-wide benefit is less than the electricity-customer benefit. In other words, when customers pay less, generators may earn less, leaving the economy-wide benefit to be less than the direct benefits electricity customers may enjoy.

Geographic Scope of the Study. Transmission investments can affect a wide range of market participants in regions adjacent to where a project is located. When estimating the overall benefits of this type of transmission project, the impacts on consumers and generators in neighboring regions need to be considered as well. In some situations, the overall benefits of a transmission project may exceed the benefits realized in a particular region because additional benefits may accrue to electricity customers and generators in neighboring regions. It is also possible that the benefits to electricity customers in the region where the project is located exceed the overall economy-wide benefit if the transmission project increases electricity customers' costs in the neighboring regions. For example, a new transmission line that allows for local electricity customers to purchase power at lower prices from a neighboring market may cause wholesale prices to increase in that neighboring market, possibly benefitting generators but increasing electricity customers' costs in the neighboring market.[22]

Economy-wide Benefits Not Reflected in Electricity Rates. The benefits of transmission investments may also extend beyond the direct benefits to electricity market participants. This is the case when some of the economy-wide benefits of transmission investments accrue to society more broadly—external to the scope of electricity costs, generator profits, or system reliability. For example, a reduction of greenhouse gas emissions due to a shift in generation resources towards more renewable energy resources resulting from a transmission upgrade can provide a societal benefit. Without a market that places an explicit monetary cost on the emissions, the societal benefit associated with reduced emissions would not materialize in reduced costs to electricity customers. Only if a price was placed on greenhouse gas emissions (as is the case for SO_2 and NO_x emissions) will the benefits associated with emissions reduction accrue to electricity customers through reduced costs. However, even though these emissions are not priced today, it is important to value on a probabilistic basis—including from a risk mitigation perspective—the likelihood that they will be priced in the future. Economy-wide benefits can also include the employment and economic development benefits of expanding the existing transmission infrastructure,[23] including benefits from stimulating the local economy, producing additional tax revenues, supporting industrial growth, or allowing the development of renewable power projects that, in turn, provide many similar economic stimulus benefits. However, the jobs and economic stimulus associated with constructing and maintaining the transmission system would only provide incremental benefits to a region if alternative investment activities

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22 For a simplified illustration and discussion of how economy-wide benefits compare to electricity customer and generator benefits in two regions interconnected by a transmission upgrade, see also Hogan, 2011.

23 However, it is important to ensure that the partial macroeconomic impacts associated with changes in spending in the power sector is not directly added to the spending effects already accounted for in the other benefit categories.

could not offer similar benefits.[24] Thus, while it is useful to estimate the potential employment and economic stimulus benefits associated with certain transmission investments, they cannot simply be added to other project benefits for the purpose of benefit-cost analyses.

Overall, we recommend using a societal or economy-wide perspective (with a sufficiently wide geographic scope) when evaluating the benefits and costs of transmission projects. However, due to regulatory requirements or for cost allocation purposes, it may also be necessary to conduct the analysis from an electricity customer perspective. In either case, it is important to deliberately specify how market structure and the geographic scope of the study will affect the investments' benefits and costs. Evaluating impacts from an electricity customer perspective should also consider benefits (such as increased reliability) that are not reflected in electricity rates.

C. Distribution of Benefits to Inform Project Cost Allocation

When evaluating the benefits associated with a new transmission project, one of the initial questions is "Who will be the beneficiaries?" FERC ratemaking has always focused on cost causation and cost responsibility. FERC has articulated the "beneficiary-pays" principle, and FERC Order 1000 specifically requires that cost allocation be "at least roughly commensurate with estimated benefits" and those that receive no benefit must not be allocated costs involuntarily. However, such cost allocation should not be based only on a narrowly defined set of benefits for which the specific value to individual market participants can be determined precisely. This is consistent with findings by Judge Posner, writing for the U.S. Court of Appeals in an unanimous decision upholding challenges to MISO's MVP tariff related to the relevance of a range of benefits and the spread of beneficiaries:

> No one can know how fast wind power will grow. But the best guess is that it will grow fast and confer substantial benefits on the region served by MISO.… There is no reason to think these benefits will be denied to particular subregions of MISO. Other benefits of MVPs, such as increasing the reliability of the grid, also can't be calculated in advance, especially on a subregional basis, yet are real and will benefit utilities and consumers in all of MISO's subregions.[25]

The estimation of how benefits are distributed and the associated identification of beneficiaries often will influence how transmission costs are allocated. While sponsors of transmission projects will generally want to demonstrate high levels of benefits for their projects for both planning and cost allocation purposes, many stakeholders may be overly skeptical about some of these benefits because of their implications on cost allocation. The possibility of being allocated

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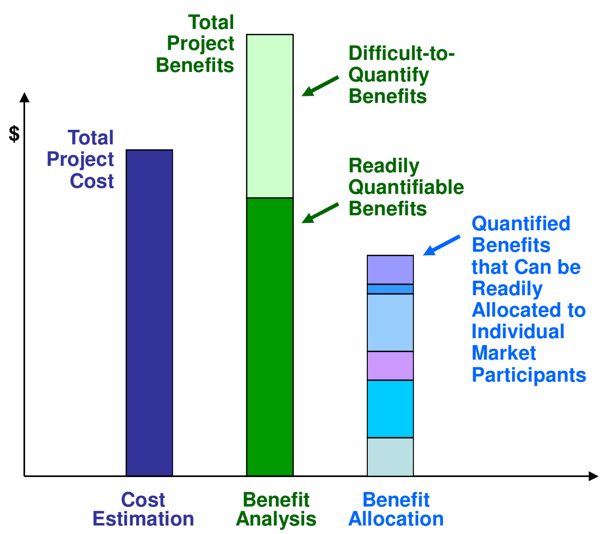
[24] For example, if workers are fully employed in an economy, building more transmission may not offer additional employment benefits to the region, and job creation alone does not necessarily or automatically ensure that certain investments provide a productive use of the associated investment capital. Further, the employment-related benefits from constructing transmission facilities would need to be weighed against the economic implications of potential increases in electricity rates.

[25] *Illinois Commerce Commission v. FERC*, No. 11-3421 *et al.*, 2013 WL 2451766 (7th Cir. June 7, 2013) , p. 12.

an unwarranted share of the projects' costs can provide certain market participants with strong incentives to question the benefits they are estimated to receive, to insist on evaluating only a limited set of benefits of a proposed project (both within a system footprint or region and between regions), and to limit planning horizons to the foreseeable future instead of over the life of the investment. Thus, narrowly interpreting and implementing the "beneficiaries-pay" framework can create strong incentives to dismiss categories of legitimate benefits on grounds that they are too uncertain or not measurable with sufficient precision, or understate them in an attempt to reduce beneficiaries' share of costs. An analysis that ignores or rejects benefits that are not measured with precision implicitly assumes that the value of such benefits is zero. This will systematically understate the overall value of transmission investments.[26] It will also, in turn, lead to the unintended consequence of rejecting valuable transmission projects that offer a broad set of long-term benefits with total values that exceed project costs.

Rejecting projects based on the misperception that the value is less than the projects' costs is illustrated in Figure 4, showing that the sum of the benefits readily allocated to individual market participants can be significantly below a project's overall, economy-wide benefits.

Figure 4



To avoid such pitfalls, we recommend that benefits be identified, analyzed, and applied in four steps as previously discussed: (1) allow projects to be proposed and benefits identified; (2) estimate the identified benefits from an economy-wide perspective; (3) compare the benefits to the costs and determine if a project provides net benefits overall; and (4) determine cost allocations of beneficial projects roughly based on the benefits received by the identified beneficiaries. We recommend that planning efforts first estimate a project's overall economic

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26 Assuming that the value of a "soft" benefit is zero is often the worst possible estimate. Even if an estimate of a material benefit or cost is imprecise due to the nature or timing of the benefit, using that estimate will often yield a more accurate assessment than using zero or assuming zero. For example, if one does not exactly know what a hotel may be charging for a night when planning a visit to New York City, it would not make sense to assume the hotel will be free.

benefits without considering how those benefits might be distributed. That way, planning efforts are focused on developing the most socially-beneficial transmission projects as opposed to selecting only those projects whose beneficiaries are easiest to identify. Planning and stakeholder processes that focus too early on cost allocation or limit the scope of benefits to traditional benefit metrics or those estimated by pre-existing analytical tools will fail to identify potentially beneficial projects to the detriment of overall market efficiency and economy-wide benefits.

Once portfolios of projects that are beneficial from an overall, economy-wide perspective are identified, several approaches can be used to allocate costs in a manner that is roughly commensurate with the estimated distribution of benefits. While using the ratio of the value of benefits received by the different parties would seem to be preferable—particularly if estimates of the distribution of the monetary value are available for most if not all of the projects' overall benefits—cost allocations based on non-monetary metrics can be more practical as long as it can be shown that these metrics result in cost allocations that are roughly commensurate with the allocation of overall economic benefits. For example, costs could be allocated to beneficiaries based on each entity's relative contribution to the need for a project—as long as such relative contributions to need are roughly proportionate to the benefits received by each entity. Costs could also be allocated based on each entity's projected or allocated usage share of the projects' added transmission capability (*e.g.*, allocated shares of increased flow-gate capacity). Other examples of cost allocations include applying load-ratio shares or shares of power flows that drive reliability-based upgrades, apportioning costs based on the power purchases of various load-serving entities when allocating the costs of renewables-integration driven projects, or using the project's physical location in each entity's footprint (*e.g.*, shares of circuit miles or direct assignment of project segments) if there is agreement that such usage or footprint-based shares are roughly proportionate to the benefits received by each party.[27]

Understanding how benefits from portfolios of projects within and across regions will be distributed across many stakeholders is also useful in determining how the costs of transmission projects should be allocated intra- and interregionally.[28] However, before determining the actual distribution of benefits, it is advisable to aggregate transmission projects across the region because the overall benefits of a portfolio of transmission projects will tend to be more evenly distributed. For example, transmission lines that allow for increased imports of lower-cost generation from a neighboring region can provide benefits to both regions: the importing region through a lower cost of delivered power and the exporting region through increased revenues to the exporting suppliers. The increased export revenue can also be a benefit to electricity customers in the exporting region if these additional revenues are used to offset the cost of regulated generation assets or if wheeling out the revenues paid by exporting merchant generators can be used to offset the exporting region's transmission revenue requirements. The same project may also provide reliability benefits to customers in both regions. While these benefits can be distributed quite unevenly for individual projects, as a larger portfolio of projects,

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27 For a discussion of these cost allocation options in the context of interregional projects, see Pfeifenberger and Hou, 2012b, pp. 58-61.

28 For a discussion of interregional cost allocations, see Section IV.D below. See also Pfeifenberger and Hou, 2012.

the benefit distribution is more likely to be evened out. Having evenly distributed benefits will tend to diffuse contentiousness of cost allocation and facilitate broader stakeholder support of proposed transmission plans.

D. Considering Benefits for Interregional Planning

Transmission planning and benefit estimation is particularly challenging for interregional transmission projects. The current lack of clarity on joint planning and how benefits should be considered for interregional projects has created what some have called a "demilitarized zone" or gap of transmission investments near or across market seams. Because there is not a single transmission planning entity that considers all benefits that accrue to multiple regions, beneficial projects often cannot be identified through current planning processes. This gap in interregional planning was recognized by FERC when it issued Order 1000, which explicitly notes that "the lack of coordinated transmission planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers of transmission providers, which may result in rates that are unjust and unreasonable and unduly discriminatory or preferential."[29] In an attempt to avoid such an outcome, the Order requires the development of interregional planning processes that identify the transmission needs across regions and a method to allocate costs associated with the interregional solutions to meet those needs.

Interregional transmission planning is especially challenging given the number of barriers that can prevent the identification of interregional projects.[30] In part because individual interregional projects may appear at first to offer a very different mix of benefits (*e.g.*, reliability, market efficiency, and public policy benefits) to each of the neighboring regions and their transmission owners, a failure by neighboring regions to recognize the full range of benefits provided by such projects is perhaps the most significant barrier to effective interregional planning. This barrier can be labeled the "least common denominator trap" as it is created by the natural tendency of neighboring transmission planning entities to evaluate only the subset of benefits that are considered in both of the neighboring regions' planning processes. In fact, we have observed regions conducting interregional benefit calculations that consider only those benefits metrics that are utilized in *both* regions' benefit estimation methodologies. For example, if each of two neighboring planning entities typically considers six different types of transmission benefits, but only three of them are considered by both entities, the respective regions reviewing an interregional project might agree to use only the three benefits that are common to both regions. This practice will generally reduce the types of benefits considered in interregional planning compared to the types of benefits that each of the planning entities will consider in their respective regional planning efforts.

This "least common denominator" approach will disadvantage interregional projects because relying on a smaller subset of benefits will tend to understate the value of the projects. To avoid such outcomes, we recommend that each of the neighboring regions, at a minimum, evaluate its

[29] FERC Order 1000, P 350.

[30] For a detailed discussion of barriers to interregional transmission planning and cost allocation and a framework of how to address these barriers, see Pfeifenberger and Hou, 2012b, and Pfeifenberger, Chang, and Hou, 2012.

share of an interregional project's benefits by including all types of benefits considered in its own internal transmission planning efforts. Using this approach, the total benefits of the interregional project will be at least equal to the sum of the benefits that each entity determines for its own footprint, considering the full set of the benefits that would be considered for each entity's own regional projects. In this way, benefits and metrics can comprehensively cover all reliability, operations, public policy, and economic benefits considered in both regions, even if these benefits are not defined and measured the same way in each region.

In addition, to the extent possible under applicable tariffs and planning processes, each region should also make an effort to consider some or all of the benefits (and associated metrics) used by the other region, even if these benefits and metrics are not currently used in its internal planning process. Moreover, interregional planning processes should recognize that projects might offer unique benefits beyond those currently considered in either region's internal transmission planning process, such as incremental wheeling revenues or benefits from increased reserve sharing capability. Further, interregional projects could at times avoid or delay the cost of other upgrades, such as projects already included in each region's existing plans, or upgrades that might be needed in the future to meet local or regional needs, or to satisfy generation interconnection or transmission service requests. These considerations may affect the net value of some proposed projects and should be examined carefully.

V. CURRENT SCOPE OF REGIONAL TRANSMISSION BENEFIT-COST ANALYSES

Transmission planning has developed over the past decade and continues to evolve with the issuance of FERC Order No. 1000 and the tariff filings that implement it. While most RTOs initially added planning processes that allowed for the evaluation of "economic" or "market efficiency" projects, these processes tended to be focused on transmission projects that could be justified via production cost savings that resulted from the congestion-relief provided by the projects. In most recent years, several RTOs have continued to expand the scope of transmission benefits considered in their planning processes to include, for example, metrics related to public-policy requirements and resource adequacy benefits. At the same time, transmission planning in non-RTO regions has also evolved beyond addressing expected reliability violations. For example, regional planning in most non-RTO regions now considers the benefits of avoiding local reliability projects, realized when larger regional transmission projects provide more cost-effective solutions than the local reliability projects proposed by individual transmission owners.

This section summarizes the range of the economic benefits of transmission investments that are currently considered in the transmission planning efforts of various regions and provides examples of the extent to which federal and state regulatory commissions have recognized these benefits in evaluating project proposals.

A. TRANSMISSION BENEFITS CONSIDERED BY RTOS

Over the past decade, several RTOs have significantly expanded the scope of the transmission benefits considered in their planning efforts to include a range of economic and public-policy benefits. Initial steps were taken by CAISO in 2004 to support the planning of multi-utility, multi-purpose, and renewable integration projects. RTOs in regions with significant renewable generation potential, such as SPP and MISO, have similarly expanded the scope of the transmission benefits considered in their planning processes—particularly in efforts to better coordinate transmission planning for the integration of renewable resources.

1. Focus on Reliability Needs and Production Cost Savings

Currently, while the exact methodologies differ, four RTOs (NYISO, ERCOT, ISO-NE, and PJM[31]) are primarily planning for reliability needs and are using estimated production cost savings to screen for new "economic" or "market efficiency" transmission projects. As an example, along with its standard reliability analyses, NYISO performs an economic evaluation process for transmission projects called the Congestion Assessment and Resource Integration Study (CARIS). In that process, NYISO estimates the state-wide production cost savings by simulating its system with and without the proposed transmission project. The resulting production cost savings estimate is compared to project costs in the NYISO's benefit-cost ratio analysis.[32] Other benefits can also be estimated through the CARIS process—such as emissions costs, load and generator payments, installed capacity costs, and Transmission Congestion Contract value—for the purpose of later developing cost allocations, but these additional benefits are not included in the benefit-cost ratio used to determine whether to proceed with the project.[33]

In PJM, the economic evaluation process for transmission projects through the Regional Transmission Expansion Plan (RTEP) focuses on determining whether reliability projects identified through traditional reliability studies can be enhanced to provide additional "market efficiency" benefits.[34] PJM estimates production cost savings and reductions in the cost of energy to load-serving entities to determine the economic benefits of transmission projects.[35] PJM applies a Benefit-to-Cost Ratio Threshold of 1.25-to-1 to determine whether to proceed with certain projects by comparing the present value of estimated benefits to the present value of the projects' revenue requirements over a 15-year period. At the time of authoring this report, other economic benefits are not considered in this evaluation process.

31 NYISO, ERCOT, ISO-NE, and PJM.

32 Similar to the traditional approach used by other planning entities, NYISO calculates production cost savings only as the change in simulated variable generation cost, including fuel costs, variable operating and maintenance (O&M) costs, and emissions costs. The limitations of this traditional approach are discussed in Section VI below.

33 NYISO, 2012.

34 The goals of the RTEP market efficiency analysis are to: (1) determine which reliability upgrades, if any, have an economic benefit if accelerated; (2) identify new transmission upgrades that may result in economic benefits; and (3) identify economic benefits associated with modification to the reliability-based enhancements that are already included in RTEP but, when modified, would also relieve one or more economic constraints.

35 PJM 2011 RTEP. PJM's estimates economic benefit as the weighted average of the estimated change in region-wide production cost (70% weight) and the change in load energy payment (30% weight). The change in load energy payment is calculated as the change in total load payments based on estimated locational marginal price minus the change in transmission right credits (PJM 2011 RTEP).

Recognizing the limits of its economic project planning process, PJM has started to collaborate with states within its region to expand its RTEP process to include public-policy-driven transmission projects and to implement a "multi-driver" planning process. The development of this multi-driver process builds on PJM's methodology of expanding reliability projects and determining whether the incremental cost of certain project expansions are justified by the incremental benefits. In the case of public-policy-driven projects, the transmission investments would have to be proposed and paid for by PJM member states[36] as "Supplemental Projects" to RTEP.[37]

ERCOT, starting with transmission needs identified in its reliability analysis, identifies potential "economic" alternatives to the reliability projects based on the sum of estimated production cost savings and the deferred or avoided cost of the displaced reliability projects. To determine whether to proceed with an economic transmission project, ERCOT estimates and compares the production cost savings for a single year (*e.g.*, 5 years out in its Five-Year Plan and 10 years out in its Long-Term System (LTS) Assessment) to the first year's revenue requirements for the project. Similarly recognizing the limitations of its current approach, ERCOT has initiated an effort to increase the scope of its planning processes.[38]

In ISO-NE, stakeholders may submit a request for ISO-NE to perform an economic study to estimate the production costs savings from proposed market-efficiency transmission projects. ISO-NE determines in its evaluation process whether a proposed transmission project will "result in: (i) a net reduction of total production costs for system load, (ii) reduced congestion, or (iii) the integration of new resources and/or loads."[39] The 2012 ISO-NE Regional System Plan (RSP) states that the ISO is currently conducting studies on the economic benefits of transmission projects based on metrics including "production costs, LSE energy expenses, congestion, environmental emissions, average LMPs, fuel consumption and energy production by fuel type, revenues from the energy market, and the capital investment supported by simulated energy revenues."[40]

In both ERCOT and ISO-NE, in addition to analyzing transmission projects driven by market efficiency, the RTOs are analyzing the transmission projects proposed to support the increased use of renewable generation, particularly as those projects help deliver remotely located resources to load centers. With the goal of building over 18,000 MW of wind generation capacity, ERCOT and the Public Utility Commission of Texas developed transmission plans for accessing wind generation from Competitive Renewable Energy Zones (CREZ). While the additional benefits of the CREZ projects are recognized by the Texas regulators, the projects have been developed primarily to meet public-policy goals objectives. ISO-NE conducts a similar review of the transmission needs to meet the RPS goals in New England. It is doing so

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36 The guidelines for proposing public-policy projects are provided in the State Agreement Approach outlined in a letter from the Organization of PJM States, Inc. (OPSI) on June 12, 2012 (OPSI, 2012).

37 PJM RPPTF 2012

38 For a summary of this effort, see Pfeifenberger and Chang, 2013.

39 ISO-NE, 2012, p. 44. See also FERC, 2008, 123 FERC ¶ 61,161.

40 ISO-NE, 2013, note 41, p. 32.

through a collaborative process with the New England State Committee on Electricity (NESCOE), which is made up of policy representatives from each of the New England states. If the results of the study are positive, the identified public-policy-driven transmission projects can be sponsored and paid for by the supporting states.[41]

2. Evolving Practices in Considering a Broader Range of Transmission Benefits

The scope of the transmission-related benefits considered by CAISO, SPP, and MISO is significantly broader than that of NYISO, ERCOT, ISO-NE, and PJM. For instance, recognizing that additional transmission would have significantly mitigated the costs incurred during the California power crisis, California modified its transmission review process to consider a broad range of transmission-related benefits. Accordingly, the CAISO created its transmission economic assessment methodology (TEAM) in 2004 to "establish a standard methodology for assessing the economic benefit of major transmission upgrades that can be used by California regulatory and operating agencies and market participants."[42] The TEAM process, at that time, significantly expanded the scope of CAISO transmission planning to include benefits from the increased competition, risk mitigation capability of transmission infrastructure, and the ability to import lower-cost energy and capacity from other regions.[43]

The TEAM approach specifically recognized that:

> [A] significant portion of the economic value of a transmission upgrade is realized when unexpected or unusual situations occur. Such situations may include high load growth, high gas prices, or wet or dry hydrological years. The 'expected value' of a transmission upgrade should be based on both the usual or expected conditions as well as on the unusual but plausible situations. A transmission investment can be viewed as a type of insurance policy against extreme events. Providing the additional capacity incurs a capital and operating cost, but the benefit is that the impact of extreme events is reduced or eliminated.[44]

The California Public Utilities Commission (CPUC) adopted the broad scope of transmission benefits considered through the TEAM approach. Specifically applying the approach, the CPUC approved the Palo Verde-Devers No. 2 (PVD2) transmission project, recognizing transmission benefits including:

- Production cost savings and reduced energy prices from both a societal (*i.e.*, economy-wide) and customer perspective;
- Mitigation of market power;
- Insurance value for high-impact, low-probability events;

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41 ISO-NE, 2012.

42 CAISO TEAM Report, 2004.

43 CAISO PVD2 Report, 2005.

44 CAISO TEAM Report, 2004, p. ES-10.

- Capacity benefits due to reduced generation investment costs;
- Operational benefits (such as reduced reliability-must-run costs and providing the system operator with more options for responding to transmission and generation outages);
- Reduced transmission losses;
- Facilitation of the retirement of aging power plants;
- Encouraging fuel diversity;
- Improved reserve sharing; and
- Increased voltage support.

In the CPUC's decision for the PVD2 project, the regulator drew additional attention to some of the benefits for which specific values were not measured. The CPUC noted: "discussion of these potential additional benefits…is useful in extending our attention beyond the limits of the quantitative analysis. We consider these factors in our consideration of [the project's] economic value, even though their potential benefits have not been measured."[45] The importance of these and other transmission-related benefits of transmission investments have also been discussed in a report sponsored by the California Energy Commission.[46]

The Integrated Transmission Planning (ITP) efforts by SPP have similarly moved toward examining a range of transmission-related benefits in its "Priority Projects" evaluations, such as reduced transmission losses, wind revenue impacts, and reliability benefits. The full list of benefits considered is shown in Table 2 below. Along with the benefits for which monetary values were estimated, the SPP's Economic Studies Working Group also agreed that a number of transmission benefits that require further analysis include:

- Enabling future markets;
- Storm hardening;
- Improving operating practices/maintenance schedules;
- Lowering reliability margins;
- Improving dynamic performance and grid stability during extreme events; and
- Societal economic benefits.[47]

To support cost allocation efforts, SPP's Metrics Task Force has further expanded SPP's frameworks for estimating additional transmission benefits to include the value of reduced energy losses, the mitigation of transmission outage-related costs, the reduced cost of extreme events, the value of reduced planning reserve margins or the loss of load probabilities, the increased wheeling through and out of revenues (which can offset a portion of transmission costs that need to be recovered from SPP's internal loads), and the value of meeting public-policy goals.[48] SPP's Metrics Task Force also recommended further evaluation of methodologies to estimate the value of other benefits such as the mitigation of costs associated with weather uncertainty and the reduced cycling of baseload generating units.

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45 CPUC *Opinion*, 2007, p. 50.

46 Budhraja *et al.*, 2008.

47 *Id.*, p. 37.

48 SPP, 2012.

Similarly, MISO estimates the value of a broad set of transmission benefits in the scope of its transmission planning efforts. In its Multi-Value Project (MVP) transmission planning process and associated cost-allocation methodology, MISO estimates a wide range of benefits for portfolios of projects that meet the MVP criteria.[49] In addition, MISO also stressed that the MVP portfolio provides a number of difficult-to-estimate benefits, such as enhanced generation flexibility, increased system robustness, and decreased natural gas price risk.[50] MISO is also in the process of further expanding the scope of its economic valuation process. For example, in the currently-ongoing Manitoba Hydro Wind Synergy Study,[51] MISO has estimated benefits related to production cost savings, load cost savings, ancillary service cost savings, wind generation changes, and thermal plant cycling reduction. In addition, MISO noted (but did not estimate) capacity benefits, potential operating reserve benefits (new reserve resources), and the storage and energy benefits of the most flexible new hydro generation. These benefits are evaluated further through sensitivity and risk assessment.

FERC has also recognized the importance of the broad range of benefits provided by transmission investments. For example, FERC specifically noted in its approval of SPP's Highway-Byway transmission tariff that:

> [R]elying solely on the costs and benefits identified in a quantitative study … may not accurately reflect the [benefits] of a given transmission facility, particularly because such tests do not consider any of the qualitative (*i.e.*, less tangible), regional benefits inherently provided by an [extra-high voltage] transmission network.[52]

Several states have also recognized that transmission projects can provide a broad range of benefits. The Wisconsin Public Service Commission approved in June 2008 its first "economic" transmission line, the Paddock-Rockdale project. That project was approved based on both estimated and qualitatively-discussed economic benefits (for seven alternative future scenarios) that included: (1) adjusted production cost savings; (2) energy and capacity cost savings from reduced transmission losses; (3) reduced power purchase costs due to increased competition; (4) reliability and system failure insurance benefits; (5) long-term resource cost advantages; (6) lower reserve margin requirements; and (7) benefits from the increased availability of financial transmission rights (FTRs).[53]

Table 2 below summarizes the transmission-related benefits discussed above and compares the metrics used in the various RTOs planning processes.[54] Additional transmission-related benefits

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49 MISO, 2011, pp. 25-44.

50 *Id.*, pp. 53-63.

51 MISO, 2013.

52 FERC, 2010, 131 FERC ¶ 61,252.

53 ATC (2007).

54 For a discussion of the evolving scope of RTO transmission-planning efforts see also Pfeifenberger Direct Testimony, 2012a; and Pfeifenberger (2012).

may be considered within individual utilities' integrated resource planning (IRP) processes and will depend on state regulatory requirements.

Table 2
Transmission Benefits Considered in RTO Planning Processes

RTO Planning Process	Estimated Benefits	Other Benefits Considered (without necessarily estimating their value)
CAISO TEAM (as applied to PVD2)	• Production cost savings and reduced energy prices from both a societal and customer perspective • Mitigation of market power • Insurance value for high-impact low-probability events • Capacity benefits due to reduced generation investment costs • Operational benefits (RMR) • Reduced transmission losses • Emissions benefits	• Facilitation of the retirement of aging power plants • Encouraging fuel diversity • Improved reserve sharing • Increased voltage support
SPP ITP Analysis	• Production cost savings • Reduced transmission losses • Wind revenue impacts • Natural gas market benefits • Reliability benefits • Economic stimulus benefits of transmission and wind generation construction	• Enabling future markets • Storm hardening • Improving operating practices/maintenance schedules • Lowering reliability margins • Improving dynamic performance and grid stability during extreme events • Societal economic benefits
Additional benefits recommended by SPP's Metrics Task Force	• Reduced energy losses, • Reduced transmission outage costs • Reduced cost of extreme events • Value of reduced planning reserve margins or loss of load probability • Increased wheeling through and out revenues • Value of meeting public policy goals	• Mitigation of weather uncertainty • Mitigation of renewable generation uncertainty • Reduced cycling of baseload plants • Increased ability to hedge congestion costs • Increased competition and liquidity
MISO MVP Analysis	• Production cost savings • Reduced operating reserves • Reduced planning reserves • Reduced transmission losses • Reduced renewable generation investment costs • Reduced future transmission investment costs	• Enhanced generation policy flexibility • Increased system robustness • Decreased natural gas price risk • Decreased CO_2 emissions output • Decreased wind generation volatility • Increased local investment and job creation
NYISO CARIS	• Reliability benefits • Production cost savings	• Emissions costs • Load and generator payments • Installed capacity costs • Transmission Congestion Contract value
PJM RTEP	• Reliability benefits • Production cost savings	• Public policy benefits
ERCOT LTS	• Reliability benefits • Production cost savings • Avoided transmission project costs	• Public policy benefits
ISO-NE RSP	• Reliability benefits • Net reduction in total production costs	• Public policy benefits

B. Transmission Benefits Considered in Non-RTO Regions

In the non-RTO transmission planning processes, the predominant method for analyzing transmission benefits is based on identifying the regional transmission projects that provide a lower-cost solution to those projects identified through the individual utilities' local planning processes. In addition, individual vertically-integrated utilities may consider a range of generation and transmission alternatives when planning for system reliability, economics, and public policy goals under their states' Integrated Resource Planning (IRP) requirements. In the context of IRPs, a wide range of transmission-related benefits also can be analyzed to evaluate the merits of specific projects or groups of projects.

In Florida and the Southeast U.S.—through the Southeastern Regional Transmission Planning Process (SERTP) and the North Carolina Transmission Planning Collaborative (NCTPC)—state-level IRP requirements are the primary process for creating the list of local projects to be considered at the regional level. Under these processes, the only economic benefit considered for regional projects is the avoided cost of local projects. Production cost estimations are not conducted to evaluate the merits of the regional projects.

At the regional level, the Florida regional planning group refers to its bottom-up process as a "roll-up" of the individual utility transmission plans, followed by a top-down analysis of whether more "Cost Effective and/or Efficient Regional Transmission Solutions" (CEERTS) projects can be identified to avoid or defer the costs of the local projects. In SERTP, only those transmission lines rated 300 kV and above that traverse over 100 miles and cross more than two balancing areas are considered regional in nature. SERTP views its process as an "*ex ante* method for determining costs and benefits" that avoids dependencies on highly uncertain energy prices and other forward market assumptions used in production cost and similar market simulations.[55] In North Carolina, the NCTPC has considered adding additional economic benefits to their transmission planning process but, after negative feedback from participants, decided to exclude the use of any estimated production cost benefits.[56]

In the Western Interconnect, the Western Electricity Coordinating Council (WECC) performs a system-wide study of transmission expansion based on input from several transmission planning subgroups. The sub-groups include one RTO (CAISO) and three non-RTO regions (ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect). While WECC notes the difficulty of performing production cost simulations in its region due to uncertain long-term contract and fuel prices and the differences in scheduling rules within its footprint,[57] production costs simulations are used to calculate the energy costs savings of transmission projects in WECC's long-term transmission planning studies. The savings associated with reductions in the capital costs of generation and transmission additions are estimated separately.

[55] SoCos, 2013, pp. 17–20.

[56] Duke, 2012, pp. 32–33.

[57] WECC, 2011, pp. 19–21.

The non-RTO regions in WECC also use the avoided costs of local transmission projects as a benefit of regional transmission lines. However, WestConnect is developing a process to evaluate additional transmission benefits through the efforts of its Cost Allocation Strike Team. Recommendations have been made that benefits be calculated based on the type of transmission project being considered, and that the evaluation of economic projects includes an assessment of the savings associated with reductions of production costs and reserve sharing requirements.[58] NTTG also evaluates whether new transmission projects will provide benefits associated with reducing energy losses and the costs of providing reserves.[59] ColumbiaGrid is currently relying only on the avoided cost metric.[60]

Table 3 summarizes the economic benefits of regional transmission projects considered in the regional planning processes of non-RTO regions. Even if some of the benefits are not considered explicitly within the transmission planning process, some of them already may be considered within state-regulated integrated resource planning efforts.

Table 3
Transmission Benefits Considered in Non-RTO Regional Planning Processes

Non-RTO Planning Organization	Benefits Considered in Regional Planning
WECC	• Avoided local transmission project costs • Production cost savings • Reduced generation capital costs
ColumbiaGrid	• Avoided local transmission project costs
NTTG	• Avoided local transmission project costs • Reduced energy losses • Reduced reserve costs
WestConnect	• Avoided local transmission project costs • Production cost savings • Reserve sharing benefits
SERTP	• Avoided local transmission project costs
NCTPC	• Avoided local transmission project costs
Florida Sponsors	• Avoided local transmission project costs

58 WestConnect, 2012. Since WestConnect is not an RTO, note that it is important that the *hurdle rate* is calculated to ensure that the transactions modeled are likely to actually occur.

59 NTTG, 2012, p 32.

60 ColumbiaGrid, 2012, Appendix A, Section 10.3.2.2, p. 18.

As explained previously, the limited scope of the transmission benefits that are considered in the regional planning processes of many non-RTO regions does not mean that other benefits do not exist in these regions. For instance, even if locational prices are not used in the market, the potential benefits of projects that reduce congestion and related production costs can still be estimated. Thus, a similar approach to estimating transmission benefits would appropriately apply in the Southeast as it would elsewhere.

As noted, some utilities in non-RTO regions are at times considering in their individual or joint planning efforts a broader range of transmission-related benefits than those formally specified in their FERC-approved regional planning processes. For example, through facilitation by a state commissioner, Entergy Gulf States Louisiana, Cleco Power, and Lafayette Utilities System jointly considered the various economic benefits associated with the approximately $200 million Acadiana Load Pocket (ALP) project. The ALP project consists of a series of new transmission lines and substations to address a variety of reliability and economic considerations in south-central Louisiana. The ALP region had been experiencing several problems, including an increase in the use of transmission loading relief (TLR) procedures to curtail non-firm transmission service, an over-reliance on inefficient generating units needed for voltage support, disconnects between modeling assumptions and actual operational limits, a lack of operational flexibility in the load pocket, and limitations to the accommodation of additional transmission service. A joint planning study documented a range of benefits from the transmission investment that would accrue to the three utilities individually and jointly. The study found that approximately $70 million of the project was justified by the reduced use of TLR procedures (thereby allowing for increased economic import) and improved load serving capability in the region. The rest, approximately $130 million of the project, was found to be justified by allowing for the removal of must-run generation, production cost (*i.e.*, fuel cost) savings, and additional generation dispatch flexibility.[61]

Similarly, the Western Area Power Administration (WAPA)—which owns and operates transmission systems in both western and eastern interconnections—stated in its 2011 Strategic Plan that it will use a business case analysis to evaluate the benefits, costs, and risks of new transmission projects. It stated, for example, that transmission planning aims to: (1) meet or exceed national and regional reliability standards; (2) support renewable energy development and deliver renewable power to markets; (3) reduce vulnerability to supply disruption; (4) increase flexibility to meet customers' needs for electricity; and (5) provide access to surplus generating capacity to protect and maximize the value of WAPA's generating resources.[62]

[61] Pfeifenberger and Hou (2012b), pp. 35-41.

[62] WAPA, 2011.

VI. CURRENT EXPERIENCE IN THE EVALUATION OF TRANSMISSION BENEFITS

This section of the report presents a technical discussion of the range of the economic benefits of transmission investments identified in Table 1 above and summarizes the available experience on how they are estimated. It also documents current industry practices in the analysis of these benefits, describes in detail how certain benefits not traditionally quantified can be measured, and explains why they are important in assessing the benefit-cost impact of proposed transmission projects.[63] Consistent with Table 1, the transmission benefits discussed in more detail include:

1. Production cost savings;
2. Reliability and resource adequacy benefits;
3. Generation capacity cost savings;
4. Market benefits, such as improved competition and market liquidity;
5. Environmental benefits;
6. Public policy benefits; employment and economic development benefits; and
7. Other project-specific benefits such as storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits.

A. PRODUCTION COST SAVINGS

The most commonly used metric for measuring the economic benefits of transmission investments is the reductions in production costs. Production cost savings include savings in fuel and other variable operating costs of power generation that are realized when transmission projects allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies. Lower production costs will generally also reduce market prices as lower-cost suppliers will set market clearing prices more frequently than without the transmission project. The tools used to estimate the changes in production costs and wholesale electricity prices are typically security-constrained production cost models that simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints.

1. Definition and Method of Calculating "Adjusted Production Cost" Savings

Within production cost models, changes in system-wide production costs can be estimated readily. These estimated changes, however, do not necessarily capture how costs change within

63 Some of the discussion in this section is taken from the recent SPP Metrics Task report we helped prepare (SPP, 2012).

individual regions or utility service areas. This is because the cost of serving these regions and areas will not only depend on the production cost of generating plants within the region or area, but will also depend on the extent to which power is bought from or sold to neighbors. The production costs within individual areas thus need to be "adjusted" for such purchases and sales. This is approximated through a widely-used benefit metric referred to as Adjusted Production Costs (APC).

Adjusted production costs for an individual utility are typically calculated as the sum of (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the net cost of the utility's market-based power purchases and sales.[64] The traditional method for estimating the changes in the APC associated with a proposed transmission project is to compare the adjusted production costs with and without the transmission project. Analysts typically call the market simulations without the transmission project the "Base Case" and the simulations with the transmission project the "Change Case."

These simulations can also provide estimates of how the proposed transmission projects affect the pattern of transmission congestion, the overall production costs necessary to serve load, the prices that utilities (and ultimately their customers) pay for market-based energy purchases, and the revenues that generators receive for market-based energy sales. Thus, through production cost simulations, one can quantify the direction and magnitude of cost and price changes by comparing the results from the Change Case with those from the Base Case.

For example, SPP estimated that its Priorities Projects will result in $1.3 billion of adjusted production cost savings. This amount of APC savings is equal to approximately 62% of the estimated costs of the transmission projects that enable those savings.[65]

2. Limitations of Production Cost Simulations and Estimated APC Savings

While production cost simulations are a valuable tool for estimating the economic value of transmission projects and have been used in the industry for many years, the specific practices continue to evolve. RTOs and transmission planners are increasingly recognizing that traditional production cost simulations are limited in their ability to estimate the full congestion relief and production cost benefits. These limitations, caused by necessary simplifications in assumptions and modeling approaches, tend to understate the likely future production cost savings associated with transmission projects. In most cases, the simplified market simulations assume:

- No change in transmission-related energy losses as a result of adding the proposed transmission project;
- No planned or unplanned transmission outages;

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64 For example, APC for a utility is typically calculated as: (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the cost of market-based power purchases valued at the simulated LMPs of the utility's load locations (Load LMP), net of (3) the revenues from market-based power sales valued at the simulated LMP of the utility's generation locations (Gen LMP).

65 SPP, 2010b, p. 26.

- No extreme contingencies, such as multiple or sustained generation and transmission outages;
- Weather-normalized peak loads and monthly energy (*i.e.*, no extreme weather conditions);
- Perfect foresight of all real-time market conditions;
- Incomplete plant cycling costs;
- Over-simplified modeling of ancillary service-related costs;
- Incomplete simulation of reliability must-run conditions;
- Unrealistically optimal system utilization in "Day-1" markets

In some cases, we also have observed that market simulations did not consider forced generation outages.[66]

We discuss each of the common limitations listed above in Subsections 3 through 11, and provide examples of how the components of production cost savings that are not captured due to these simplifying assumptions can be or have been estimated.[67] Following that, Subsection 12 discusses how adjusted production cost calculations simplify the estimated charges for congestion and marginal transmission losses, which can result in the under- or over-estimation of transmission-related benefits from an electricity-customer's perspective.

3. Estimating Changes in Transmission Losses

In some cases, transmission additions or upgrades can reduce the energy losses incurred in the transmittal of power from generation sources to loads. However, due to significant increases in simulation run-times, a constant loss factor is typically provided as an input assumption into the production cost simulations. This approach ignores that the transmission investment may reduce the total quantity of energy that needs to be generated, thereby understating the production cost savings of transmission upgrades.

To properly account for changes in energy losses resulting from transmission additions will require either: (1) simulating changes in transmission losses; (2) running power flow models to estimate changes in transmission losses for the system peak and a selection of other hours; or (3) utilizing marginal loss charges (from production cost simulations with constant loss approximation) to estimate how the cost of transmission losses will likely change as a result of the transmission investment.[68] Through any of these approaches, the additional changes in production costs associated with changes in energy losses (if any) can be estimated.

In some cases, the economic benefits associated with reduced transmission losses can be surprisingly large, especially during system peak-load conditions. For instance, the energy cost

66 For example, forced outages are not currently considered in the simulations performed for the evaluation of economic projects in ERCOT's long-term transmission planning process.

67 See *also ibid.*, Section 4.

68 For a discussion of estimating loss-related production cost savings from the marginal loss results of production cost simulations see *ibid.*, Section 4.2. See also Pfeifenberger Direct Testimony, 2008.

savings of reduced energy losses associated with a 345 kV transmission project in Wisconsin were sufficient to offset roughly 30% of the project's investment costs.[69] Similarly, in the case of a proposed 765 kV transmission project, the present value of reduced system-wide losses was estimated to be equal to roughly half of the project's cost.[70] For transmission projects that specifically use advanced technologies that reduce energy losses, these benefits are particularly important to capture. For example, a recent analysis of a proposed 765 kV project using "low-loss transmission" technology showed that this would provide an additional $11 to 29 million in annual savings compared to the older technology.[71]

4. Estimating the Additional Benefits Associated with Transmission Outages

Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect *transmission* outages, planned or unplanned. Both generation and transmission outages can have significant impacts on transmission congestion and production costs. By assuming that transmission facilities are available 100% of the time, the analyses tend to under-estimate the value of transmission upgrades and additions because outages, when they occur, typically cause transmission constraints to bind more frequently and increase transmission congestion and the associated production costs significantly.[72]

Transmission outages account for a significant and increasing portion of real-world congestion. For example, when the PJM FTR Task Force reported a $260 million FTR congestion revenue inadequacy (or approximately 18% of total PJM congestion revenues during the 2010–11 operating year), approximately 70% of this revenue inadequacy was due to major construction-related transmission outages (16%), maintenance outages (44%), and unforeseen transmission de-ratings or forced outages (9%). In fact, the frequency of PJM transmission facility rating reductions due to transmission outages has increased from approximately 500 per year in 2007 to over 2,000 in 2012.[73] Similarly, while the exact amount attributable to transmission outages is not specified, the Midwest ISO's independent market monitor noted that congestion costs in the day-ahead and real-time markets in 2010 rose 54 percent to nearly $500 million due to higher loads and transmission outages.[74] MISO also recently addressed the challenge of FTR revenue inadequacy by using a representation of the transmission system in its simultaneous FTR feasibility modeling that incorporates planned outages and a derate of flowgate capacity to

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69 ATC, 2007, pp. 4 (project cost) and 63 (losses benefit).

70 Pioneer, 2009, at p. 7. These benefits include not only the energy value (*i.e.*, production cost savings) but also the capacity value of reduced losses during system peak.

71 Pfeifenberger and Newell Direct Testimony, 2011.

72 For an additional discussion of simulating the transmission outage mitigation value of transmission investments, see SPP, 2010b, Section 4.3.

Also note that, while not related to production costs, the transmission outages can also result in reduced system flexibility that can delay certain maintenance activities (because maintenance activities could require further line outages), which in turn can reduce network reliability.

73 PJM FTR Report 2012, p. 32. See also PJM FTR Presentation, 2011.

74 Patton, 2011.

account for unmodeled events such as unplanned transmission outages and loop flows.[75] As aging transmission facilities need to be rebuilt, the magnitude and impact of transmission outages will only increase.

A 2005 study of PJM assessed the impact of transmission outages. That analysis showed that without transmission outages, total PJM congestion charges would have been 20% lower; the value of FTRs from the AEP Generation Hub to the PJM Eastern Hub would have been 37% lower; the value of FTRs into Atlantic Electric, for example, would have been more than 50% lower; and that simulations without outages generally understated prices in eastern PJM and west-east price differentials.[76] These examples show that real-world congestion costs are higher than congestion costs in a world without transmission outages. This means that the typical production cost simulations, which do not consider transmission outages, tend to understate the extent of congestion on the system and, as a result, the congestion-relief benefit provided by transmission upgrades.

Production cost simulations can be augmented to reflect reasonable levels of outages, either by building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by reducing the limits that will induce system constraints more frequently. For the RITELine transmission project, specific production cost benefits were analyzed for the planned outages of four existing high-voltage lines. It was found that a one-week (non-simultaneous) outage for each of the four existing lines increased the production cost benefits of the RITELine project by more than $10 million a year, with PJM's Load locational pricing payments decreasing by more than $40 million a year. Because there are several hundred high-voltage transmission elements in the region of the proposed RITELine, the actual transmission-outage-related savings can be expected to be significantly larger than the simulated savings for the four lines examined in that analysis.[77]

At the time of writing this report, our ongoing work for SPP indicates that applying the most important transmission outages from the last year to forward-looking simulations of transmission investments increases the estimates of adjusted production cost savings by approximately 10% to 15% even under normalized system (e.g., peak load) conditions. Higher additional transmission–outage-related savings are expected in portions of the grid that already have very limited operating flexibility and during challenging (i.e., not normalized) system conditions.

The fact that transmission outages increase congestion and associated production costs is also documented for non-RTO regions. For example, Entergy's Transmission Service Monitor (TSM) found that transmission constraints existed during 80% of all hours, leading to 331 curtailments of transmission services, at least some of which was the result of the more than 2,000 transmission outages that affected available transmission capability during a three month

75 See Section 7.1 (Simultaneous Feasibility Test) of the MISO Business Practices Manuals. Posted at: https://www.midwestiso.org/LIBRARY/BUSINESSPRACTICESMANUALS/Pages/BusinessPracticesManuals.aspx.

76 Pfeifenberger and Newell, 2006.

77 Pfeifenberger and Newell Direct Testimony, 2011.

period.[78] The TSM report also showed that, for the five most constrained flowgates on the Entergy system, the available flowgate capacity during real-time operations generally fluctuated by several hundred MW over time. This means that the actual available transmission capacity is less on average than the limits used in the market simulation models, which assume a constant transmission capability equal to the flowgate limits used for planning purposes. This also indicates that the traditional simulations tend to understate transmission congestion by not reflecting the lower transmission limits in real-time. The TSM report also stated that the identified transmission constraints resulted in the refusal of transmission service requests for approximately 1.2 million MWh during the same three month period.

These examples show that real-world congestion costs are higher than the congestion costs simulated through traditional production cost modeling that assumes a world without transmission outages. These values associated with new transmission's ability to mitigate the cost of transmission outages will be particularly relevant in areas of the grid with constrained import capability and limited system flexibility.

5. Estimating the Benefits of Mitigating the Impacts of Extreme Events and System Contingencies

Transmission upgrades can provide insurance against extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages. Even if a range of typical generation and transmission outage scenarios are simulated during analyses of proposed projects, production cost simulations will not capture the impacts of extreme events; nor will they capture how proposed transmission investments can mitigate the potentially high costs resulting from these events. Although extreme events occur very infrequently, when they do they can significantly reduce the reliability of the system, induce load shed events, and impose high emergency power costs. Production cost savings from having a more robust transmission system under these circumstances include the reduction of high-cost generation and emergency procurements necessary to support the system. Additional economic value (discussed further below) includes the value of avoided load shed events.

The insurance value of additional transmission in reducing the impact of extreme events can be significant, despite the relatively low likelihood of occurrence. While the value of increased system flexibility during extreme contingencies is difficult to estimate, system operators intrinsically know that increased system flexibility provides significant value. One approach to estimate these additional values is to use extreme historical market conditions and calculate the probability-weighted production cost benefits through simulations of the selected extreme events. For example, a production cost simulation analysis of the insurance benefits for the Paddock-Rockdale 345 kV transmission project in Wisconsin found that the project's probability-weighted savings from reducing the production and power purchase costs during a number of simulated extreme events (such as multiple transmission or nuclear plant outages similar to actual events that occurred in prior years) added as much as $28 million to the production cost savings, offsetting 20% of total project costs.[79]

78 Potomac Economics (2013).

79 ATC, 2007, pp. 4 (project cost) and 50-53 (insurance benefit).

For the PVD2 project, several contingency events were modeled to determine the value of the line during these high-impact, low-probability events. The events included the loss of major transmission lines and the loss of the San Onofre nuclear plant. The analysis found significant benefits, including a 61% increase in energy benefits, to CAISO ratepayers in the case of the San Onofre outage.[80] This simulated high-impact, low-probability event turned out to be quite real, as the San Onofre nuclear plant has been out of service since early 2012 and will now be closed permanently.[81]

Further, the analysis of high-impact, low-probability events also documented that—while the estimated societal benefit (including competitive benefit) of the PVD2 line was only $77 million for 2013—there was a 10% probability that the annual benefit would exceed $190 million under various combinations of higher-than-normal load, higher-than-base-case gas prices, lower-than-normal hydro generation, and the benefits of increased competition. There was also a 4.8% probability that the annual benefit ranged between $360 and $517 million.[82]

6. Estimating the Benefits of Mitigating Weather and Load Uncertainty

Production cost simulations are typically performed for all hours of the year, though the load profiles used typically reflect only normalized monthly and peak load conditions. Such methodology does not fully consider the regional and sub-regional load variances that will occur due to changing weather patterns and ignores the potential benefit of transmission expansions when the system experiences higher-than-normal load conditions or significant shifts in regional weather patterns that change the relative power consumption levels across multiple regions or sub-regions. For example, a heat wave in the southern portion of a region, combined with relatively cool summer weather in the north, could create much greater power flows from the north to the south than what is experienced under the simulated normalized load conditions. Such greater power flows would create more transmission congestion and greater production costs. In these situations, transmission upgrades would be more valuable if they increased the transfer capability from the cooler to hotter regions.[83]

SPP's Metrics Task Force recently suggested that SPP's production simulations should be developed and tested for load profiles that represent 90/10 and 10/90 peak load conditions—rather than just for base case simulations (reflecting 50/50 peak load conditions)—as well as scenarios reflecting north-south differences in weather patterns.[84] Such simulations may help analyze the potential incremental value of transmission projects during different load conditions.

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80 CPUC *Opinion*, 2007, pp. 37–41.

81 See Wald, 2013.

82 CAISO PVD2 Report, 2005, p. 24.

83 Because the incremental system costs associated with higher-than-normal loads tend to exceed the decremental system costs of lower-than-normal loads, the probability-weighted average production costs across the full spectrum of load conditions tend to be above the production costs for normalized conditions.

84 See SPP, 2012, Section 9.6.

While it is difficult to estimate how often such conditions might occur in the future, they do occur, and ignoring them disregards the additional value that transmission projects provide under these circumstances. For example, simulations performed by ERCOT for normal loads, higher-than-normal loads, and lower-than-normal loads in its evaluation of a Houston Import Project showed a $45.3 million annual consumer benefit for the base case simulation (normal load) compared to a $57.8 million probability-weighted average of benefits for all three simulated load conditions.[85]

7. Estimating the Impacts of Imperfect Foresight of Real-Time System Conditions

Another simplification inherent in traditional production cost simulations is the deterministic nature of the models that assumes perfect foresight of all real-time system conditions. Assuming that system operators know exactly how real-time conditions will materialize when system operators must commit generation units in the day-ahead market means that the impact of many real-world uncertainties are not captured in the simulations. Changes in the forecasted load conditions, intermittent resource generation, or plant outages can significantly change the transmission congestion and production costs that are incurred due to these uncertainties.

Uncertainties associated with load, generation, and outages can impose additional costs during unexpected real-time conditions, including over-generation conditions that impose additional congestion costs. For example, comparing the number of negatively priced hours in the real-time versus the day-ahead markets in the ComEd load zone of PJM provides an example of how dramatically load and intermittent resource conditions can change.[86] From 2008 to 2010, there were 763 negatively priced hours in the real-time market, but only 99 negatively priced hours in the day-ahead market. The increase in negative prices in the real-time, relative to the day-ahead, market is due to the combined effects of lower-than-anticipated loads with the significantly higher-than-predicted output of intermittent wind resources. While this example illustrates the impact of uncertainties within the day-ahead time frame, traditional production cost simulations do not consider these uncertainties and their impacts.

Thus, to estimate the additional benefits that transmission upgrades can provide with the uncertainties associated with actual real-time system conditions, traditional production cost simulations need to be supplemented. For example, existing tools can be modified so that they simulate one set of load and generation conditions anticipated during the time that the system operators must commit the resources, and another set of load and generation conditions during real-time. The potential benefits of transmission investments also extend to uncertainties that need to be addressed through intra-hour system operations, including the reduced quantities and prices for ancillary services (such as regulation and spinning reserves) needed to balance the system as discussed further below.[87] These benefits will generally be more significant if

[85] ERCOT, 2011, p. 10. The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant's estimated probabilities for the same scenarios.

[86] Pfeifenberger and Newell Direct Testimony, 2011.

[87] For example, a recent study for the National Renewable Energy Laboratory (NREL) concluded that, with 20% to 30% wind energy penetration levels for the Eastern Interconnection and assuming substantial

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transmission investments allow for increased diversification of uncertainties across the region, or if the investments increase transmission capabilities between renewables-rich areas and resources in the rest of the grid that can be used to balance variances in renewable generation output.[88]

8. Estimating the Additional Benefits of Reducing the Frequency and Cost of Cycling Power Plants

With increased power production from intermittent renewable resources, some conventional generation units may be required to operate at their minimum operating levels and cycle up and down more frequently to accommodate the variability of intermittent resources on the system. Additional cycling of plants can be particularly pronounced when considering the uncertainties related to renewable generation that can lead to over-commitment and over-generation conditions during low loads periods. Such uncertainty-related over-generation conditions lead to excessive up/down and on/off cycling of generating units. The increased cycling of aging generating units may reduce their reliability, and the generating plants that are asked to shut down during off-peak hours may not be available for the following morning ramp and peak load periods, reducing the operational flexibility of the system. Some of these operational issues could reduce resource adequacy and increase market prices when the system must dispatch higher-cost resources.

Transmission investments can provide benefits by reducing the need for cycling fossil fuel power plants by spreading the impact of intermittent generation across a wider geographic region. Such projects provide access to a broader market and a wider set of generation plants to respond to the changes in generation output of renewable generation.

The cost savings associated with the reduction in plant cycling would vary across plants. A recent study of power plants in the Western U.S. found that increased cycling can increase the plants' maintenance costs and forced outage rates, accelerate heat rate deterioration, and reduce the lifespan of critical equipment and the generating plant overall. The study estimated that the total hot-start costs for a conventional 500 MW coal unit are about \$200/MW per start (with a range between \$160/MW and \$260/MW). The costs associated with equipment damage account for more than 80% of this total.[89]

Continued from previous page

transmission expansions and balancing-area consolidation, total system operational costs caused by wind variability and uncertainty range from \$5.77 to \$8.00 per MWh of wind energy injected. The day-ahead wind forecast error contributes between \$2.26/MWh and \$2.84/MWh, while within-day variability accounts for \$2.93/MWh to \$5.74/MWh of wind energy injected. See EnerNex, 2013 (\$/MWh in US\$2024).

88 For a simplified framework to consider both short-term and long-term uncertainties in the context of transmission and renewable generation investments, see Munoz, *et al.*, 2013; Van Der Weijde and Hobbs, 2012; and Park and Baldick, 2013.

89 See Kumar, *et al.*, 2012. The study is based on a bottom-up analysis of individual maintenance orders and failure events related to cycling operations, combined with a top-down statistical analysis of the relationship between cycling operations and overall maintenance costs. See *Id.* (2011), p. 14. Costs inflated from \$2008 to \$2012. Note that the Intertek-APTECH's 2012 study prepared for NREL (Kumar, *et al.*, 2012) reported only 'lower-bound' estimates to the public.

Production cost simulations can be used to measure the impact of transmission investments on the frequency and cost of cycling fossil fuel power plants. However, the simplified representation of plant cycling costs in traditional production cost simulations—in combination with deterministic modeling that does not reflect many real-world uncertainties—will not fully capture the cycling-related benefits of transmission investments. Although SPP's Metrics Task Force recently suggested that production simulations be developed and tested,[90] this is an area where standard analytical methodology still needs to be developed.

9. Estimating the Additional Benefits of Reduced Amounts of Operating Reserves

Traditional production cost simulations assume that a fixed amount of operating reserves is required throughout the year, irrespective of transmission investments. Most market simulations set aside generation capacity for spinning reserves; regulation-up requirements may be added to that. Regulation-down requirements and non-spinning reserves are not typically considered. Such simplifications will understate the costs or benefits associated with any changes in ancillary service requirements. The analyses typically disregard the costs that integrating additional renewable resources may impose on the system or the potential benefits that transmission facilities can offer by reducing the quantity of ancillary services required. Such costs and benefits will become more important with the growth of variable renewable generation.

The estimation of these benefits consequently requires an analysis of the quantity and types of ancillary services at various levels of intermittent renewable generation, with and without the contemplated transmission investments. The Midwest ISO recently performed such an analysis, finding that its portfolio of multi-value transmission projects reduced the amount of operating reserves that would have to be held within individual zones, which allowed reserves to be sourced from the most economic locations. MISO estimated that this benefit was very modest, with a present value of $28 to $87 million, or less than one percent of the cost of the transmission projects evaluated.[91] In other circumstances, where transmission can interconnect regions that require additional supply of ancillary services with regions rich in resources that can provide ancillary services at relatively low costs (such as certain hydro-rich regions), these savings may be significantly larger. However, to quantify these benefits often requires specialized simulation tools that can simulate both the impacts of imperfect foresight and the costs of intra-hour load following and regulation requirements. Most production cost simulations are limited to simulating market conditions with perfect foresight and on an hourly basis.

Finally, a number of organized power markets do not co-optimize the dispatch of energy and ancillary services resources. Other regions with co-optimized markets may still require some location-specific unit commitment to provide ancillary services. If not considered in market simulations, this can understate the potential benefits associated with transmission-related congestion relief.

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[90] SPP, 2012, Section 9.4.

[91] MISO, 2011, pp. 29-33.

10. Estimating the Benefits of Mitigating Reliability Must-Run Conditions

Traditional production cost simulation models determine unit commitment and dispatch based on first contingency transmission constraints, utilizing a simple direct current (DC) power-flow model. This means that the simulation models will not by themselves be able to determine the extent to which generation plants would need to be committed for certain local reliability considerations, such as for system stability and voltage support and to avoid loss of load under second system contingencies. Instead, any such “reliability must run” (RMR) conditions must be identified and implemented as a specific simulation input assumption. Both existing RMR requirements and the reduction in these RMR conditions as a consequence of transmission upgrades need to be determined and provided as a modeling input separately for the Base Case and Change Case simulations.

RMR-related production cost savings provided by transmission investments can be significant. For example, a recent analysis of transmission upgrades into the New Orleans region shows that certain transmission projects would significantly alleviate the need for RMR commitments of several local generators. Replacing the higher production costs from these local RMR resources with the market-based dispatch of lower-cost resources resulted in estimated annual production cost savings ranging from approximately $50 million to $100 million per year.[92] Avoiding or eliminating a set of pre-existing RMR requirements needed to be specified as model input assumptions.

11. Estimating Production Costs in “Day-1” Markets

When analyzing transmission benefits in bilateral, non-RTO markets, it is important to recognize that generation unit commitment and dispatch in such “Day-1” markets is not the same as in an LMP-based RTO market. Thus, if simulated as security-constrained LMP-based regional markets, the simulations would understate the benefit of transmission investments in non-RTO markets by over-optimizing the system operations compared to real-world outcomes. To recognize some of the realities of such “Day-1” markets, planners have traditionally imposed “hurdle rates” on transactions between individual balancing areas. This is important to prevent the simulations from over-optimizing system dispatch relative to actual market outcomes. However, relying solely on hurdle rates to approximate realistic market outcomes may not be sufficient. Thus, derates of transmission limits may also be necessary to capture the fact that congestion management through transmission loading relief (TLR) processes in “Day-1” markets typically results in under-utilization of flow-gate limits. For example, an analysis of RTO-market benefits by the Department of Energy (DOE) assumed that improved congestion management and internalization of power flows by ISOs result in a 5-10% increase in the total transfer capabilities on transmission interfaces.[93] Similarly, a study of congestion management in MISO’s “Day-1” market found that, during 2003, available flowgate capacities were underutilized by between 7.7% to 16.4% on average within MISO subregions during TLR events

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92 Pfeifenberger Direct Testimony, 2012a, pp. 48-49.

93 USDOE, 2003, pp. 7-8 and 41-42.

compared to the flows that could have been accommodated had the grid been efficiently dispatched using a regional security-constrained economic dispatch.[94]

We recommend that "Day-1" market simulations use both hurdle rates and derates to more realistically approximate actual market conditions (in both base and change case simulations). Hurdle rates as traditionally used will appropriately decrease flows between balancing areas, reduce congestion, and thus reduce the economic value of increased transmission between balancing areas. In contrast, derates will tend to simulate more realistic level of congestion within and across balancing areas, which will tend to increase the estimated production cost savings of transmission upgrades. These potential additional production cost savings will not be captured in traditional market simulations that rely solely on hurdle rates to approximate "Day-1" market conditions.

12. Estimating Overall Economic and Electricity-Customer Savings

System-wide production cost savings from the simulations of transmission investments as discussed in this section represent economy-wide benefits. In a regulatory environment where all generation is cost-of-service regulated with no market-based purchases and off-system sales, these system-wide savings will also reflect customer benefits for the entire simulated footprint—which usually includes all neighboring regions. To measure transmission-related benefits to an individual region, individual utilities, or other load-serving entities (LSEs), analysts typically rely on metrics such as Adjusted Production Costs (APC) and Load LMP costs. As noted above, these metrics can approximate electricity-customer benefits but they differ from the magnitude of the economy-wide benefits. The magnitude of these benefits depends on assumptions about market structure and the extent to which LSEs would be exposed to cost-based generation, market-based purchases and sales, and (within RTO markets) marginal loss charges and unhedged congestion charges.

For example, the APC metric measures the change in variable costs of generation within (or contracted to) an LSE's service area, adjusted for market-based purchases and sales. As a measure of customer impacts, the metric approximates customer costs for a vertically-integrated, cost-of-service regulated utility environment, consistent with simplifying assumptions that: (1) all owned or contracted resources supply power at variable production costs; (2) all imports and other non-cost-based purchases are market-based, priced at the area's internal Load LMP (*i.e.*, no fixed-priced contracts and assuming congestion charges for imports and purchases could not be hedged with allocated FTRs); (3) all off-system sales from an LSE's cost-based resources are priced at the area-internal Generation LMP; (4) no congestion costs charges are incurred in transmitting energy from cost-based generation to load within the LSE's service area (*i.e.*, all transactions from cost-based resources are fully hedged with allocated FTRs); and (5) no marginal loss charges are incurred on transactions from cost-based resources.

The load-weighted LMP metric measures the change in market-based power purchase costs that would be paid by customers in an LSE's service area if all load was served at LMPs at the load's

[94] McNamara Affidavit, 2004, p. 14.

location. This metric thus approximates customer impacts in a retail access environment, implicitly reflecting an assumption that all load is served at market prices without any cost-of-service-based generation, long-term contracts, FTR allocations that would hedge congestion charges, or the partial refunds of marginal-loss-related charges.

Because some RTO service areas cover both cost-of-service regulated, vertically-integrated utilities as well as LSEs that supply customers through market-based purchases, both APC and Load LMP metrics may be relevant. In fact, PJM has defined a blended metric based on a 70% APC and 30% Load-LMP weighted average. This hybrid metric roughly represents a market structure under which retail rates reflect roughly 70% cost-based generation that is fully hedged against congestion charges and 30% market-based generation (including imports) that is entirely unhedged through FTR allocations.[95]

While these metrics and the simplifying assumptions used to derive them will be sufficient in many cases, a more accurate calculation of customer impacts for individual utilities or LSEs may be necessary because these traditional metrics do not explicitly take into account a number of energy and congestion-related factors that can be important in estimating the impacts of transmission investments from a customer-cost perspective. In particular, they may need to be modified to more accurately account for: (1) the degree of cost-based versus market-based generation; (2) long-term contracts and their pricing (*e.g.*, variable-cost based, fixed, or market-based); (3) the level of FTR coverage for a service area's internal and contracted generation; (4) the level of FTR coverage for imports into the service area; (5) the extent to which the transmission projects make additional FTRs available to LSEs in the service area; and (6) the difference between marginal loss charges, loss refunds, and the simulation's treatment of energy losses.[96]

B. Reliability and Resource Adequacy Benefits of Transmission Projects

This and the following subsections of our report address transmission-related benefits that are not reflected in production cost savings. As noted earlier, production cost savings only measure the reduction in variable production costs, including fuel, variable O&M costs, and emission costs.[97] This means that production cost savings, even if the simulations capture the additional factors discussed above, will not capture the benefits associated with reliability, capital costs, increased competition, certain environmental benefits and other public policy benefits, or economic development benefits. These benefits provide additional value to electricity customers and to the economy as a whole.

Transmission investments will generally increase the reliability of the electric power system even when meeting reliability standards is not the primary purpose of the line. For example,

95 MISO also previously used this hybrid (70%/30%) metric for production cost savings but has changed to a 100% Adjusted Production Cost Savings metric as they have found it better represents their load characteristics (MISO, 2012).

96 For an example of more detailed estimates of customer impacts, see Pfeifenberger Direct Testimony, 2008.

97 Emissions costs are only considered to the extent that the simulations assume a price for emissions such as SO_2, NO_x, and in some cases CO_2.

additional transmission investment made for market efficiency and public policy goals can avoid or defer reliability upgrades that would otherwise be necessary, increase operating flexibility, reduce the risk of load shed events, and increase options for recovering from supply disruptions. This increase in reliability provides economic value by reducing the frequency, duration, and magnitude of load curtailments—or, alternatively, by reducing the planning reserve margins needed to maintain resource adequacy targets, such as a 1-day-in-10-year loss of load probability. These reliability benefits are not captured in production cost simulations, but can be estimated separately. Below we describe the categories of reliability and resource adequacy benefits.

1. Benefits from Avoided or Deferred Reliability Projects

When certain transmission projects are proposed for economic or public policy reasons, transmission upgrades that would otherwise have to be made to address reliability needs may be avoided or could be deferred for a number of years. These avoided or deferred reliability upgrades effectively reduce the net cost of planned economic or public-policy projects. These benefits can be estimated by comparing the revenue requirements of reliability-based transmission upgrades without the proposed project (the Base Case) to the lower revenue requirements reflecting the avoided or delayed reliability-based upgrades assuming the proposed project would be in place (the Change Case). The present value of the difference in revenue requirements for the reliability projects (including the trajectory of when they are likely to be installed) represents the estimated value of avoiding or deferring certain projects. If the avoided or deferred projects can be identified, then the avoided costs associated with these projects can be counted as a benefit (*i.e.*, cost savings) associated with the proposed new projects.

SPP, for example, uses this method to analyze whether potential reliability upgrades could be deferred or replaced by proposed new economic transmission projects.[98] Similarly, a recent projection of deferred transmission upgrades for a potential portfolio of transmission lines considered by ITC in the Entergy region found the reduction in the present value of reliability project revenue requirements to be $357 million, or 25% of the costs of the proposed new transmission projects.[99] This method has also been used by MISO, who found that the proposed MVP projects would increase the system's overall reliability and decrease the need for future baseline reliability upgrades. In fact, MISO's MVP projects were found to eliminate future transmission investments of one bus tie, two transformers, 131 miles of transmission operating at less than 345 kV, and 29 miles of 345 kV transmission.[100]

2. Benefits of Reduced Loss of Load Probability <u>or</u> Reduced Planning Reserve Margin Requirements

Even if not targeted to address identified reliability needs, transmission investments can reduce the frequency and severity of necessary load curtailments by providing additional pathways for

98 See SPP, 2012, Section 3.3.

99 Pfeifenberger Direct Testimony, 2012a, pp. 77-78.

100 MISO, 2011, pp. 42-44.

connecting generation resources with load in regions that can be constrained by weather events and unplanned outages. From a risk mitigation perspective, transmission projects provide insurance value to the system such that when contingencies, emergencies, and extreme market conditions stress the system, having a more robust grid would reduce: (1) the need to rely on higher-cost measures to avoid shedding load (a production cost benefit considered in the previous section of this paper); and (2) the likelihood of load shed events, thus improving physical reliability.

As recognized by SPP's Metrics Task Force, for example, such reliability benefits can be estimated through Monte Carlo simulations of systems under a wide range of load and outage conditions to obtain loss-of-load related reliability metrics, such as Loss of Load Hours (LOLH), Loss of Load Expectation (LOLE), and Expected Unserved Energy (EUE).[101] The reliability benefit of transmission investments can be estimated by multiplying the estimated reduction in EUE (in MWh) by the customer-weighted average Value of Lost Load (VOLL, in $/MWh). Estimates of the average VOLL can exceed $5,000 to $10,000 per curtailed MWh. The high value of lost load means that avoiding even a single reliability event that would have resulted in a blackout would be worth tens of millions to billions of dollars. As ATC notes, for example, had its Arrowhead-Weston line been built earlier, it would have reduced the impact of blackouts in the region.[102]

When a transmission investment reduces the loss of load probabilities, system operators may be able to reduce their resource adequacy requirements, in terms of the system-wide required planning reserve margin or the required reserve margins within individual resource adequacy zones of the region. If system operators choose to reduce resource adequacy requirements, the benefit associated with such reduction can be measured in terms of the reduced capital cost of generation. Effectively, the reduced cost would be estimated by calculating the difference in the cost of generation needed under the required reserve margins before adding the new transmission projects versus the cost of generation with the lower required reserve margins after adding the new transmission. Transmission investments tend to either reduce loss-of-load events (if the planning reserve margin is unchanged) or allow for the reduction in planning reserve margins (if holding loss-of-load events constant), but not both simultaneously.[103]

The potential for transmission investments to reduce the reserve margin requirement has been recognized by a number of system operators. MISO recently estimated through LOLE reliability simulations that its MVP portfolio is expected to reduce required planning reserve margins by up to one percentage point. Such reduction in planning reserves translated into reduced generation

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[101] SPP, 2012, Section 5.2.

LOLH measures the expected number of hours in which load shedding will occur. LOLE is a metric that accounts for the expected number of days, hours, or events during which load needs to be shed due to generation shortages. And EUE is calculated as the probability-weighted MWh of load that would be unserved during loss-of-load events.

[102] ATC, 2009.

[103] This is due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with a reduced loss-of-load probability (if the reserve margin requirement is not adjusted). Only one of these benefits is typically realized.

capital investment needs ranging from $1.0 billion to $5.1 billion in present value terms, accounting for 10–30% of total MVP project costs.[104] This benefit was similarly recognized by the SPP Metrics Task Force,[105] as well as by the Public Service Commission of Wisconsin, which noted that "the addition of new transmission capacity strengthening Wisconsin's interstate connections" was one of three factors that allowed it to reduce the planning reserve margin requirements of Wisconsin utilities from 18% to 14.5%.[106]

C. Generation Capacity Cost Savings

Transmission investments can also reduce generation investment costs beyond those related to increasing the reliability benefits and reduced reserve margin requirements. Transmission upgrades can also reduce generation capacity costs in the form of: (1) lowering generation investment needs by reducing losses during peak load conditions; (2) delaying needed new generation investment by allowing for additional imports from neighboring regions with surplus capacity; and (3) providing the infrastructure that allows for the development and integration of lower-cost generation resources. Below, we discuss each of these three benefits.

1. Capacity Cost Benefits from Reduced Transmission Losses

Investments in transmission often reduce generation investment needs by reducing system-wide energy losses during peak load conditions. This benefit is in addition to the production cost savings associated with reduced energy losses. During peak hours, a reduction in energy losses will reduce the additional generation capacity needed to meet the peak load, transmission losses, and reserve margin requirements. For example, in a system with a 15% planning reserve margin, a 100 MW reduction in peak-hour losses will reduce installed generating capacity needs by 115 MW.

The economic value of reduced losses during peak system conditions can be estimated through calculating the capital cost savings associated with the reduction in installed generation requirements. These capital cost savings can be calculated by multiplying the estimated net cost of new entry (Net CONE), which is the cost of new generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource-constrained, with the reduction in installed capacity requirements.[107]

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104 MISO, 2011, pp. 34-36.

105 SPP, 2012, Section 5.1.

106 PSC WI, 2008, p. 5. Two other changes that contributed to this decision were the introduction of the Midwest ISO as a security constrained independent dispatcher of electricity and the development of additional generation in the state.

107 Net CONE is an estimate of the annualized fixed cost of a new natural gas plant, net of its energy and ancillary service market profits. Fixed costs include both the recovery of the initial investment as well as the ongoing fixed operating costs of a new plant. This is an estimate of the capacity price that a utility or other buyer would have to pay each year—in addition to the market price for energy—for a contract that could finance a new generating plant.

Several planning regions have estimated the capacity cost savings associated with loss reductions due to transmission investments:

- SPP's evaluation of its Priority Projects showed $71 million in capacity savings from reduced losses, or 3% of total project costs.[108]
- ATC found that its Paddock-Rockdale project provided an estimated $15 million in capacity savings benefits from reduced losses, or approximately 10% of total project costs.[109]
- MISO also found that its MVP portfolio reduced transmission losses during system peak by approximately 150 MW, thereby reducing the need for future generation investments with a present value benefit in the range of $111 to $396 million, offsetting 1–2% of project costs.[110]
- An analysis of potential transmission projects in the Entergy footprint showed that the projects could reduce peak-period transmission losses by 32 MW to 49 MW, offering a benefit of approximately $50 million in reduced generating investment costs, offsetting approximately 2% of total project costs.[111]

2. Deferred Generation Capacity Investments

Transmission projects can defer generation investment needs in resource-constrained areas by increasing the transfer capabilities from neighboring regions with surplus generation capacity. For example, an analysis for ITC of potential transmission projects in the Texas portion of Entergy's service area showed that the transmission projects provide increased import capability from Louisiana and Arkansas. The imports allow surplus generating capacity in those regions to be delivered into Entergy's resource-constrained Texas service area, thereby deferring the need for building additional local generation. By doing so, existing power plants that have the option to serve the Entergy Texas service area and the rest of Texas (the ERCOT region) would be able to serve the resource-constrained ERCOT region, thereby addressing ERCOT resource adequacy challenges. The economy-wide benefit of the deferred generation investments was estimated at $320 million, about half of which was estimated to accrue to customers in Texas, with the other half of the benefit to accrue to merchant generators in Louisiana and Arkansas.[112] A similar analysis also identified approximately $400 million in resource adequacy benefits from deferred generation investments associated with a transmission project that increases the transfer capability from Entergy's Arkansas and Louisiana footprint to TVA. These overall economy-wide benefits would accrue to a combination of TVA customers, Arkansas and Louisiana merchant generators, and, through increased MISO wheeling-out revenues, Entergy and other MISO transmission customers.

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108 SPP, 2010b, p. 26.

109 ATC, 2007, pp. 4 (project cost) and 63 (capacity savings from reduced losses).

110 MISO, 2011, pp. 25 and 27.

111 Pfeifenberger Direct Testimony, 2012a, pp. 58-59.

112 *Id.*, pp. 69.

3. Access to Lower-Cost Generating Resources

Some transmission investments increase access to generation resources located in low-cost areas. Generation developed in these areas may be low cost due to low permitting costs, low-cost sites on which plants can be built (*e.g.*, low-cost land and/or sites with easy access to existing infrastructure), low labor costs, low fuel costs (*e.g.*, mine mouth coal plants and natural gas plants built in locations that offer unique cost advantages), access to valuable natural resources (*e.g.*, hydroelectric or pumped storage options), locations with high-quality renewable energy resources (*e.g.*, wind, solar, geothermal, biomass), or low environmental costs (*e.g.*, low-cost carbon sequestration and storage options).

While production cost simulations can capture cost savings from fuel and variable operating costs if the different locational choices are correctly reflected in the Base and Change Case simulations, the simulations would still not capture the lower overall generation investment costs. To the extent that transmission investments provide access to locations that offer generation options with lower capital costs, these benefits need to be estimated through separate analyses. At times, to accurately capture the production cost savings of such options may require that a different generation mix is specified in the production cost simulations for the Base Case (*e.g.*, with generation located in lower-quality or higher-cost locations) and the Change Case (*e.g.*, with more generation located in higher-quality or lower-cost locations).

The benefits from transmission investments that provide improved access to lower-cost generating resources can be significant from both an economy-wide and electricity customer perspective. For example, the CAISO found that the Palo Verde-Devers transmission project was providing an additional link between Arizona and California that would have allowed California resource adequacy requirements to be met through the development of lower-cost new generation in Arizona.[113] The capital cost savings were estimated at $12 million per year from an economy-wide (*i.e.*, societal) perspective, or approximately 15% of the transmission project's cost, half of which it was assumed would accrue to California electricity customers. Similarly, ATC found that its Paddock-Rockdale transmission line enabled Wisconsin utilities to serve their growing load by building coal or IGCC generating capacity at mine-mouth coal sites in Illinois instead of building new plants in Wisconsin.[114] The analysis found that sites in Illinois offered significantly lower fuel costs (or, in the future, potentially lower carbon sequestration costs) and that the transmission investment likely reduced the total cost of serving Wisconsin load compared to new resources developed within Wisconsin. In that instance, the analysis should have implemented different production cost assumptions in the Base and Change Cases to reflect the access to lower production cost generation with the new line compared to the status quo.

Access to a lower-cost generation option can also significantly reduce the cost of meeting public-policy requirements. For example, as discussed further under "public-policy benefits" in Subsection F below, the Midwest ISO evaluated different combinations of transmission investments and wind generation build-out options, ranging from low-quality wind locations that require less transmission investment to high-quality wind locations that require more

[113] CAISO PVD2 Report, 2005, pp. 25-26.

[114] ATC, 2007, pp. 54-55.

transmission investment.[115] This analysis found that the total system costs could be significantly reduced through an optimized combination of transmission and wind generation investments that allowed a portion of total renewable energy needs to be met by wind generation in high-quality, low-cost locations. Similarly, the CREZ projects in Texas have also provided new opportunities for fossil generation plants to be located away from densely populated load centers where it may be difficult to find suitable sites for new generation facilities, where environmental limitations prevent the development of new plants, or where developing such generation is significantly more costly.

D. Benefits from Increased Competition and Market Liquidity

Transmission projects can provide additional market benefits, both from an economy-wide and electricity customer rate perspective, by increasing competition in and the liquidity of wholesale power markets.

1. Benefits of Increased Competition

Production cost simulations generally assume that generation is bid into wholesale markets at its variable operating costs. This assumption does not consider that some bids will include mark-ups over variable costs, particularly in real-world wholesale power markets that are less than perfectly competitive. For this reason, the production cost and market price benefits associated with transmission investments could exceed the benefits quantified in cost-based simulations. This will be particularly true for transmission projects that expand access to broader geographic markets and allow more suppliers than otherwise to compete in the regional power market. Such effects are most pronounced during tight market conditions. Specifically, enlarging the market by transmission lines that increase transfer capability across multiple markets can decrease suppliers' market power and reduce overall market concentration. The overall magnitude of benefits from increased competition can range widely, from a small fraction to multiples of the simulated production cost savings, depending on: (1) the portion of load served by cost-of-service generation; (2) the generation mix and load obligations of market-based suppliers; and (3) the extent and effectiveness by which RTOs' market power mitigation rules yield competitive outcomes.

A lack of transmission to ensure competitive wholesale markets can be particularly costly to customers. For example, the Chair of the CAISO's Market Surveillance Committee estimated that if significant additional transmission capacity had been available during the California energy crisis from June 2000 to June 2001, electricity customer costs would have been reduced by up to $30 billion over the 12 month period during which the crisis occurred.[116] More recently, ISO New England noted that increased transmission capacity into constrained areas such as Connecticut and Boston have significantly reduced congestion, "thereby significantly reducing the likelihood that resources in the submarkets could exercise market power."[117]

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115 MISO, 2010, p. 32 and Appendix A.

116 CAISO TEAM Report, 2004, pp. ES-9.

117 FERC Performance Metrics, 2011, p. 106.

Given the experience during the California Power Crisis, the ability of transmission investment to increase competition in wholesale power markets has been considered explicitly in the CAISO's review of several proposed new transmission projects. For example, in its evaluation of the proposed Palo Verde-Devers transmission project, the CAISO noted that the "line will significantly augment the transmission infrastructure that is critical to support competitive wholesale energy markets for California consumers" and estimated that increased competition would provide $28 million in additional annual consumer and "modified societal" benefits, offsetting approximately 40% of the annualized project costs.[118] Similarly, in its evaluation of the Path 26 Upgrade transmission projects, the CAISO estimated the expected value of competitiveness benefits could offset up to 50 to 100% of the project costs, with a range depending on project costs and assumed future market conditions.[119] A similar analysis was performed for ATC's Paddock-Rockdale line, estimating that the benefits of increased competition would offset between 10 to 40% of the project costs, depending on assumed market structure and supplier behavior.[120]

2. Benefits of Increased Market Liquidity

Limited liquidity in the wholesale electricity markets also imposes higher transaction costs and price uncertainty on both buyers and sellers. Transmission expansions can increase market liquidity by increasing the number of buyers and sellers able to transact with each other, which in turn will reduce the transaction costs (*e.g.*, bid-ask spreads) of bilateral transactions, increase pricing transparency, increase the efficiency of risk management, improve contracting, and provide better clarity for long-term planning and investment decisions.

Estimating the value of increased liquidity is challenging, but the benefits can be sizeable in terms of increased market efficiency and thus reduced economy-wide costs. For example, the bid-ask spreads for bilateral trades at less liquid hubs have been found to be between $0.50 to $1.50/MWh higher than the bid-ask spreads at more liquid hubs.[121] At transaction volumes ranging from less than 10 million to over 100 million MWh per quarter at each of more than 30 electricity trading hubs in the U.S., even a $0.10/MWh reduction of bid-ask spreads due to a transmission-investment-related increase in market liquidity would save $4 million to $40 million per year for a single trading hub, which would amount to a transactions cost savings of approximately $500 million annually on a nation-wide basis.

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118 CAISO PVD2 Report, 2005, pp. 18 and 27. Under the "modified societal perspective" of the CAISO TEAM approach, producer benefits include net generator profits from competitive market conditions only. This modified societal perspective excludes generator profits due to uncompetitive market conditions.

119 CAISO TEAM Report, 2004 (using the proposed Path 26 upgrade as case study).

120 Pfeifenberger Direct Testimony, 2008; and ATC, 2007, pp. 44-47 and pp. 4 (project cost) and 63 (competitiveness benefit).

121 Pfeifenberger Oral Testimony, 2006, p. 39.

E. ENVIRONMENTAL BENEFITS

Depending on the effects of transmission expansions on the overall generation dispatch, some projects can reduce harmful emissions (*e.g.,* SO_2, NO_x, particulates, mercury, and greenhouse gases) by avoiding the dispatch of high-emission generation resources. The benefits of reduced emissions with a market pricing mechanism are largely calculated in production cost simulations for pollutants with emission prices such as SO_2 and NO_x. However, for pollutants that do not have a pricing mechanism yet, such as CO_2 in some regions, production cost simulations do not directly capture such environmental benefits unless specific assumptions about future emissions costs are incorporated into the simulations.

Not every proposed transmission project will necessarily provide environmental benefits. Some transmission investments can be environmentally neutral or even displace clean but more expensive generation (*e.g.*, displacing natural gas-fired generation when gas prices are high) with lower-cost but higher-emission generation. In some instances, a reduction in local emissions may be valuable (*e.g.*, reduced ozone and particulates) but not result in reduced regional (or national) emissions due to a cap and trade program that already limits the total of allowed emissions in the region. Nevertheless, even if specific transmission projects do not reduce the overall emissions, they may affect the costs of emissions allowances which in turn could affect the cost of delivered power to customers.

As more and more transmission projects are proposed to interconnect and better integrate renewable resources, some project proponents have quantified specific emissions reductions associated with those projects. For example, Southern California Edison estimated that the proposed Palo Verde- Devers No. 2 project would reduce annual NO_x emissions in WECC by approximately 390 tons and CO_2 emissions by about 360,000 tons per year. These emissions reductions were estimated to be worth in the range of \$1 million to 10 million per year.[122] Similarly, an analysis of a portfolio of transmission projects in the Entergy service area estimated that the congestion and RMR relief provided by the projects would eliminate approximately one million tons of CO_2 emissions from fossil-fuel generators every year.[123] That estimated emission reduction is equivalent to removing the annual CO_2 emissions from over 200,000 cars.

F. PUBLIC-POLICY BENEFITS

Some transmission projects can help regions reduce the cost of reaching public-policy goals, such as meeting the region's renewable energy targets by facilitating the integration of lower-cost renewable resources located in remote areas; while enlarging markets by interconnecting regions can also decrease a region's cost of balancing intermittent renewable resources.

As an illustration of these savings, transmission investments that allow the integration of wind generation in locations with a 40% average annual capacity factor can reduce the investment cost of wind generation by *one quarter* for the same amount of renewable energy produced compared

[122] CAISO PVD2 Report, 2005, pp. 26.

[123] Pfeifenberger Direct Testimony, 2012a, pp. 83.

to the investment costs of wind generation in locations with a 30% capacity factor.[124] Access to higher quality wind resources will reduce both economy-wide and electricity customer costs if the higher-quality wind resources can be integrated with additional transmission investment of less than the benefit, estimated to be $500 to $700 per kW of installed wind capacity.

As noted earlier, the Midwest ISO has assessed this benefit by evaluating different combinations of transmission investments and wind generation build-out options. The MISO analysis shows that the total cost of wind plants and transmission can be reduced from over $110 billion for either all local or all regional wind resources to $80 billion for a combination of local and regional wind development. The savings achieved from an optimized combination of local and regional wind and transmission investment would be over $30 billion.[125] These cost savings could be achieved by increasing the transmission investment per kW of wind generation from $422/kW in the all-local-wind case to $597/kW in the lowest-total-cost case.

A similar analysis was also carried over into MISO's analysis of its portfolio of multi-value projects, which were targeted to help the Midwestern states meet their renewable energy goals. By facilitating the integration of high-quality wind resources, MISO found that its MVP portfolio reduced the present value of wind generation investments by between $1.4 billion and $2.5 billion, offsetting approximately 15% of the transmission project costs.[126] Similarly, ATC found that its Arrowhead-Weston transmission project has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to help meet Wisconsin's RPS requirement.[127]

Additional transmission investment can also help reduce the cost associated with balancing intermittent resources. Interconnecting regions and expanding the grid allow a region to simultaneously access a more diverse set of intermittent resources than smaller systems. Such diversity would reduce the cost of balancing the system due to the "self-balancing" effect of generation output diversity and the larger pool of conventional resources that are available to compensate for the variable and uncertain nature of intermittent resources. The associated savings can be estimated in terms of the reduction of the balancing resources required (which is a fixed cost reduction) and a more efficient unit-commitment and system operations (which includes a variable cost reduction). If less generating capacity from conventional generation is needed, the reduction in capacity costs can be estimated using the Net Cost of New Entry. For the potential reduction in the operational costs associated with balancing renewable resources, if we assume that the renewable generation balancing benefit of an expanded regional grid reduces balancing costs by only $1/MWh of wind generation, the annual savings associated with 10,000 MW of wind generation at 30% capacity factor would exceed $25 million.

To summarize, even though making significant transmission investments to gain access to remotely-located renewable resources seems to increase the cost of delivering renewable

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[124] For example, see Burns & McDonnell, 2010, pp. 1–2, Figure 2.

[125] MISO, 2010, p. 32 and Appendix A.

[126] MISO, 2011, pp. 25 and 38-41.

[127] ATC, 2009, p. 7.

generation, the savings associated with reducing the renewable generation costs (by obtaining access to high quality renewable resources), reducing the system balancing costs, and achieving other reliability and economic benefits can exceed the incremental cost of those transmission projects. In such cases, despite the fact that both transmission and retail electricity rates may increase, the transmission investment can reduce the overall cost of satisfying public policy goals.[128] While this rationale will not apply to every public-policy-driven transmission project, it is instructive to consider these benefits and, if needed, estimate all potential benefits when evaluating large regional transmission investments.

G. EMPLOYMENT AND ECONOMIC STIMULUS BENEFITS

Transmission investments will also stimulate the local, regional, and national economy, supporting employment and regional economic activities. However, unlike the other economic benefits described above, the direct and indirect employment and economic stimulus associated with the construction and operations of the transmission system are benefits that do not reduce customer's electricity rates or improve their quality of service. These benefits are a measure of the effects of changes in power sector spending on other sectors in the economy, taking into account the input and output relationships among industries, consumers, and governments. For example, the construction of transmission facilities requires the use of labor and materials. Most of the manufacturing and construction activities will directly benefit the local economy by creating construction jobs. While certain input materials, such as towers and concrete, likely are sourced from within the region or from near-by regions, other materials such as cables and other electrical components may be imported from outside of the project's region or even from outside the U.S.

To measure the employment and overall economic activity supported by transmission investments, studies rely on a class of models known as input-output models.[129] Input-output models are universally used by economists and policy analysts to estimate how specified changes in spending affect every sector of a state's or region's economy.[130] Input-output models are used

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128 In developing public policy goals, state or federal policy makers may have identified benefits inherent in the policies that are not necessarily economic or immediate. For the evaluation of public policy transmission projects, however, the objective is not be to assess the benefits and costs of the public policy goal, but the extent to which transmission investments can reduce the overall cost of meeting the public policy goal.

129 Some of the studies did not utilize full input-output models but relied on the "economic multipliers" taken from these models. Nonetheless, the multipliers are consistent with input-output models and assumptions. Input-output models are based on detailed economic data on how goods and services are produced and consumed. An input-output model rebalances the overall economy after an increase in expenditures on particular types of products (*e.g.*, construction activities and electric transmission equipment) such that the quantity produced equals the quantity consumed for every industry. These models specifically consider how much of the consumed products and services are supplied from each sector of a state or region.

130 The majority of the studies we surveyed relied on the well-known and widely-used IMPLAN Model of the Minnesota IMPLAN Group (MIG) to estimate the employment and economic stimulus benefits of transmission investments. The IMPLAN (IMpact analysis for PLANning) economic impact modeling system is developed and maintained by MIG, which has continued the original work on the system done at the University of Minnesota in close partnership with the U.S. Forest Service's Land and Management Planning Unit. IMPLAN divides the economy into 440 sectors and allows the user to specify the

Continued on next page

to estimate: (1) the number of jobs supported in the region (in full-time-equivalent years or "FTE-years" of employment);[131] and (2) the economic activities generated in the region (*i.e.*, increased "economic output" as measured in total sales and resale revenues of businesses within the study region). Since these models report economic activity as the sum of the value of all goods and services sold at each level of the supply chain (*i.e.*, sales and resale revenues), the reported economic output refers to the total flow of money that occurs throughout the local economy. The measured impacts are the cumulative (undiscounted) number of jobs (or FTE-years of employment or FTE jobs each year), and the overall economic activity (in constant dollars) associated with investing in transmission projects over the entire construction phase.[132]

It is important to note, however, that the employment and economic stimulus impacts associated with the construction and operation of the transmission system are not additive to the economic benefits accruing in the power sector. In addition, increasing or decreasing costs for electric customers or increasing or decreasing profits to the investors of generators will also have downstream employment and economic stimulus effects.

Our 2011 analysis conducted for WIRES shows that every $1 billion of U.S. transmission investment directly and indirectly supports approximately 13,000 full-time-equivalent (FTE) years of employment and $2.4 billion in total economic activity.[133] Approximately one-third of this employment benefit is associated with the direct construction and manufacturing of transmission facilities. Two-thirds of the total impact is associated with indirect and induced

Continued from previous page

expenditure allocations associated with a given expansion in demand to all relevant parts of the local economy in order to derive the economic impacts—changes in employment, earnings, and economic output. According to the U.S. Department of Agriculture, currently "over 1,500 clients across the country use the IMPLAN model, making the results acceptable in inter-agency analysis." In 2009, the U.S. Army Corps of Engineers Civil Works program utilized IMPLAN employment multipliers "to estimate the potential number of jobs preserved or created" by the American Recovery and Reinvestment Act of 2009. In addition, the U.S. Department of Commerce, the Bureau of Economic Analysis, the U.S. Department of Interior, the Bureau of Land Management, and the Federal Reserve System member banks are also among the agencies that utilize IMPLAN for economic impact analysis.

[131] Employment impacts are generally reported as full-time-equivalent (FTE) job years, that is, 2,080 hours of full employment. For example, reporting 100 FTE years of employment could mean 200 full-time jobs supported for 6 months, 100 jobs supported for a year, or 10 jobs supported for 10 years.

[132] The employment and economic stimulus effects are typically quantified under three types of effects: "direct," "indirect," and "induced" impacts. <u>Direct</u> effects represent the changes in employment and economic activity in the industries which directly benefit from the investment (*i.e.*, construction companies, transmission materials and equipment manufacturing, and design services). <u>Indirect</u> effects measure the changes in the supply chain and inter-industry purchases generated from the transmission construction and manufacturing activities (*e.g.*, suppliers to transmission equipment manufacturers). <u>Induced</u> effects reflect the increased spending on food, clothing, and other services by those who are directly or indirectly employed in the construction of the transmission lines and substations. Employment supporting the three activities represents discrete net gains to the overall economy if the labor force is not being utilized elsewhere in the economy absent the projects. If the employment in a certain region is tight such that creating new jobs only allows people to change from less to more desirable jobs, very few new jobs would be created.

[133] Pfeifenberger and Hou, 2011.

employment by suppliers and service providers to the transmission construction and equipment manufacturing sectors. As shown in Table 4, the WIRES report also summarized nine previous studies of the employment and economic stimulus benefits of transmission investments, covering a wide range of regions in the U.S. as well as portions of Canada.[134]

The summary shows that the local, state-level employment impacts range from a low of 2 FTE-years of total employment supported per million dollars of investment to a high of 18 FTE-years per million of investment (shown in Table 4 column [E]), with a majority of studies showing that each million dollars of transmission investment supports between 5 and 8 FTE-years of local employment. The economic output per million dollars of total transmission capital cost ranges from a low of $0.2 million to $2.9 million (shown in Table 4, column [F]).

In addition to employment and economic output, some studies also have estimated the increase in personal income earned by employees, local tax revenues, lease payments to local landowners, and stimulus to individual industries. While not all of the studies estimate these additional employment and economic stimulus benefits (and they cannot simply be added to other project benefits for the purpose of benefit-cost analyses as discussed in Section IV.B of this report), they nevertheless represent actual flows of wealth throughout a defined regional economy.

H. Other Potential Project-Specific Benefits

Some transmission investments can create additional benefits that are very specific to the particular set of projects. These benefits may include improved storm hardening, increased load-serving capability, synergies with future transmission projects, the option value of large transmission facilities to improve future utilization of available transmission corridors, fuel diversity and resource planning flexibility, increased wheeling revenues, and the creation of additional physical or financial transmission rights to improve congestion hedging opportunities. Below, we discuss each briefly.

1. Storm Hardening

In regions that experience storm-induced transmission outages, certain transmission upgrades can improve the storm resilience of the existing grid transmission system. Strong storms that damage transmission lines can drastically affect an entire region where VOLL can be significantly large. Even if new transmission lines intended to increase system resilience are built along similar routes as existing transmission lines (and thus seemingly can be damaged by the same natural disasters), newer technologies and construction standards would allow the new projects to offer greater storm resilience than the existing transmission lines.[135]

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[134] There are several other studies discussing transmission-investment-related benefits to the regional or national economies, which are not included on our summary due to insufficient detail contained in or the different nature of these studies. For example, see Build Energy America!, 2011; McBride, *et al.*, 2008.

More recent studies not summarized in the following discussion include: Perryman, 2010; Lewis and Pfister, 2010; and Lowe *et al.*, 2011.

[135] Pfeifenberger Direct Testimony, 2012a, pp. 79–80.

Table 4
Employment and Economic Impacts of Transmission Investments per Million Dollars of Total and Local Spending

	Study Sponsor	Project Summary	% Local Spending	Based on Total Transmission Capital Cost: FTE-Years of Employment Per $ Million – Direct	Based on Total Transmission Capital Cost: FTE-Years of Employment Per $ Million – Total	Based on Total Transmission Capital Cost: Total Economic Output Per $ Million ($ Million)	Based on Local Spending: FTE-Years of Employment Per $ Million – Direct	Based on Local Spending: FTE-Years of Employment Per $ Million – Total	Based on Local Spending: Total Economic Output Per $ Million ($ Million)
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
[1]	AltaLink	AltaLink's estimated capital spending							
		Alberta	75%	5	7	N/A	7	9	N/A
		Rest of Canada Outside of Alberta	75%	N/A	3	N/A	N/A	3	N/A
[2]	ATC LLC	Two completed projects							
		1. 138 kV Femrite-Sprecher	46%	N/A	5	$0.7	N/A	11	$1.5
		2. 345 kV Arrowhead-Weston	100%	N/A	8	$1.4	N/A	8	$1.4
[3]	CapX2020	Five major transmission projects	100%	7	13	$1.9	7	13	$1.9
[4]	Central Maine Power	Maine Power Reliability	81%	4	6	N/A	5	7	N/A
[5]	Montana Department of Labor & Industry	Six major projects planned or under construction in Montana							
		1. Out-of-state contractors	11%	1	2	$0.2	11	17	$1.7
		2. In-state contractors	33%	2	5	$0.6	7	14	$1.7
		3. In- and out-of-state contractors	17%	2	3	$0.3	9	16	$1.7
[6]	Perryman Group	CREZ transmission	100%	N/A	18	$2.9	N/A	18	$2.9
[7]	South Dakota Wind Energy Association	Eastern South Dakota 345 kV transmission	25%	1	3	$0.3	8	11	$1.3
[8]	SPP	Various Priority Projects							
		1. Group 1 - low in-region	47%	4	7	$0.9	8	14	$1.8
		2. Group 1 - high in-region	74%	5	8	$1.3	6	11	$1.7
		3. Group 2 - low in-region	47%	4	7	$0.8	8	14	$1.8
		4. Group 2 - high in-region	73%	5	8	$1.2	6	11	$1.7
[9]	Wyoming Infrastructure Authority	Combination of 500 kV HVDC, 500 kV HVDC, and 230 kV HVAC	33%	5	5	$0.4	14	15	$1.3

Sources and Notes:

For full source citations, please refer to Table 3 in Pfeifenberger and Hou, 2011.

[1]: "Rest of Canada Outside of Alberta" impacts reflect AltaLink's capital spending on other provinces. The study provided a value-added impact which is not reflected in the table above.

[3]: Direct output assumed to be local spending.

[4]: The study provided a value-added impact which is not reflected in the table above.

[5]: Direct output assumed to be local spending.

[6]: The study provided a value-added impact which is not reflected in the table above.

[9]: NREL "direct" employment data have been adjusted by adding "indirect" impacts to align with other IMPLAN study definitions.

2. Increased Load Serving Capability

A transmission project's ability to increase future load-serving capability ahead of specific transmission service requests is usually not considered when evaluating transmission benefits. For example, in regions experiencing significant load growth, the existing electric system often requires costly and possibly time-consuming system upgrades when a new industrial or commercial customer with a significant amount of load is contemplating locating in a utility's service area. At times, new transmission lines built to serve other needs (such as to increase market efficiency or to meet public-policy objectives) can also create low-cost options to quickly increase load-serving capability in the future.[136]

3. Synergies with Future Transmission Projects

Certain transmission projects provide synergies with future transmission investments. For example, the building of the Tehachapi transmission project to access 4,500 MW of wind resources in the CAISO provides the option for a lower-cost upgrade of Path 26 than would otherwise be possible, as well as additional options for future transmission expansions in that region.[137] Planning a set of "no-regrets" projects that will be needed under a wide range of future market conditions can help capitalize on such "option value." For instance, the RITELine Project (spanning from western Illinois to Ohio) provides a "no regrets" step toward the creation of a larger regional transmission overlay that can integrate the substantial amount of renewable generation needed to meet the regional states' RPS requirements over the next 10 to 20 years.[138] A number of regional planning efforts (such as RGOS I, RGOS II, and SMART) have shown that the expansion of renewable generation over the next 20 years may require construction of a Midwest-wide regional transmission overlay. The RITELine Project is an element common to the transmission configurations recommended in each of these larger regional transmission studies and, thus, in addition to the project's standalone merit, creates the option of becoming an integrated part of such a regional overlay. Because the project is both valuable on a stand-alone basis and can be used as an element of the larger potential regional overlays, it can be seen as a first step that provides the option for future regional transmission buildout.

4. Up-Sizing Lines and Improved Utilization of Available Transmission Corridors

The number of right-of-way "corridors" on which new transmission lines can be built is often extremely limited, particularly in heavily populated or environmentally sensitive areas. As a result, constructing a new line on a particular right-of-way may limit or foreclose future options of building a higher-capacity line or additional lines. Foreclosing that option can turn out to be very costly. It will often be possible, however, to preserve this option or reduce the cost of foreclosing that option through the design of the transmission line that is planned and constructed now. For example, "upsizing" a transmission line ahead of actual need (*e.g.*, to a double-circuit

[136] For example, see *ibid.*, p. 80.

[137] CAISO TEAM Report, 2004, pp. 9–21. Tehachapi region referred to as Kern County.

[138] Pfeifenberger and Newell Direct Testimony, 2011.

or higher-voltage line) requires incremental investment but will greatly reduce the cost of foreclosing the option to increase capacity along the same corridor when additional transfer capability would be needed in the future. Similarly, the option to increase transmission capabilities in the future can be created, for example, by building a single-circuit line on double-circuit towers that create the option to add a second circuit in the future. Building a line rated for a higher voltage level than the voltage level at which it is initially operated (*e.g.*, building a line with 765kV equipment that is initially operated only at 345kV) creates the option to increase the transfer capability of the line at modest incremental costs in the future. While investing more today to create such low-cost options to "up-size" lines in the future may be valuable even without right of way limits, this option will be particularly valuable if finding additional right of ways would be very difficult or expensive.

5. Increased Fuel Diversity and Resource Planning Flexibility

Transmission upgrades sometimes can help interconnect areas with very different resource mixes, thereby diversifying the fuel mix in the combined region and reducing price and production cost uncertainties. Projects also can provide resource planning flexibility by strengthening the regional power grid and lowering the cost of addressing future uncertainties, such as changes in the relative fuel costs, public policy objectives, coal plant retirements, or natural gas delivery constraints.

6. Benefits Related to Relieving Constraints in Fuel Markets

Additional transmission lines can provide benefits associated with relieving constraints in fuel markets. For example, recent reliability concerns in New England concerning gas-electric coordination issues caused by the increasing reliance on natural gas fired generation and limitations on pipeline capacity could be alleviated by additional import capacity for wholesale power from outside New England. In addition, increased diversity of generation resources enabled by new transmission lines can reduce the demand and price of fuel.[139]

7. Increased Wheeling Revenues

As mentioned in the context of interregional cost allocation, a transmission line that increases exports (or wheeling through) of low-cost generation to a neighboring region can provide additional benefits to the exporting region's customers through increased wheeling out revenues. The increase in wheeling revenues, paid for by the exporting generator or importing buyer, will offset a portion of the transmission projects' revenue requirements, thus reducing the net costs to the region's own transmission customers. While not an economy-wide benefit, increasing a transmission owner's wheeling revenues is equivalent to allocating some of the project costs to exporters and/or neighboring regions. For example, our analysis of an illustrative portfolio of transmission projects in the Entergy region estimated that approximately $400 million of potential resource adequacy benefits were realized from deferred generation investment needs in the TVA service area by exporting additional amounts of surplus capacity from merchant

[139] Budhraja *et al.*, 2008, pp. 43-44.

generators in the Entergy region. While this is a benefit that accrues in large part to TVA customers and merchant generators in the Entergy region, approximately $130 million of the $400 million benefits accrue to Entergy and MISO customers in the form of additional MISO wheeling revenues after Entergy joins MISO, which partially offset the transmission projects' revenue requirements that would need to be recovered from Entergy/MISO customers and other market participants.[140]

8. Increased Transmission Rights and Customer Congestion-Hedging Value

A transmission project that increases transfer capabilities between lower-cost and higher-cost regions of the power grid can provide customer benefits by providing access in the form of increasing the availability of physical transmission rights in non-RTO markets or across RTO boundaries. Within RTOs, the transmission upgrade would increase financial transmission rights that can be requested by and allocated to load-serving entities. The availability of additional FTRs increases the proportion of congestion charges that can be hedged by LSEs, thereby reducing congestion-related uncertainty. The additional FTRs can also reduce an area's customer costs by allowing imports from lower-cost portions of the region.[141] While a transmission upgrade may result in increased FTR revenues to LSEs from additional FTRs, the customer benefit of these additional revenues tends to be offset by revenue decreases from existing FTRs because the project will reduce congestion charges (and therefore reduce revenues from existing FTRs). For example, our analysis of the congestion and FTR-related impacts for the Paddock-Rockdale project in Wisconsin showed that these customer impacts can range widely—from increasing traditional APC estimates by approximately 50% in scenarios with low APC savings to decreasing traditional APC estimates by approximately 35% in scenarios with high APC savings.[142]

9. Operational Benefits of High-Voltage Direct-Current Transmission Lines

The addition of high-voltage direct-current ("HVDC") transmission lines can provide a range of operational benefits to system operators by enhancing reliability and reducing the cost of system operations. These operational benefits of HVDC lines, which in large part stem from the projects' new converter technologies, are broadly recognized in the industry. For example, various authors note that the technology can be used to: (1) provide dynamic voltage support to the AC system, thereby increasing its transfer capability;[143] (2) supply voltage and frequency support;[144] (3) improve transient stability[145] and reactive performance;[146] (4) provide AC system

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140 For example, see Pfeifenberger Direct Testimony, 2012a, pp. 73-76.

141 As noted earlier, this benefit is not captured in the traditional adjusted production cost (APC) and Load LMP metrics, because the metrics assume that all imports are priced at the load's location (*i.e.*, the area-internal Load LMP).

142 Pfeifenberger Direct Testimony, 2008, Appendix A; and ATC, 2007, p. 63 (FTR and congestion).

143 Bahrman (2008), p. 5.

144 Wang, *et al.*, 2008, p. 19.

145 IEEE PES, 2005, p. 75.

damping;[147] (5) serve as a "firewall" to limit the spread of system disturbances;[148] (6) "decouple" the interconnected system so that faults and frequency variations between the wind farms and the AC network or between different parts of the AC network do not affect each other;[149] and (7) provide blackstart capability to re-energize a 100% blacked-out portion of the network.[150] For example, PJM recognized these benefits in its evaluation of the HVDC option for the Mid-Atlantic Power Pathway project.[151] It was also found that the proposed Atlantic Wind Connection HVDC submarine project's ability to redirect flow instantaneously will provide PJM with additional flexibility to address reliability challenges, system stability, voltage support, improved reactive performance, and blackstart capability.[152]

VII. RECOMMENDATIONS

Recent developments in transmission planning around the country show that the industry and regulators have reached a point where a more complete catalogue of benefits and the methodologies for estimating benefits is being articulated and understood. Based on this industry experience and our own, we assembled a comprehensive list of economic benefits that transmission investments can provide. We recommend that this list of benefits be used as a "checklist" during initial transmission project conceptualization efforts to help planners identify potentially beneficial projects and their associated benefits. The likely benefits of the proposed projects should then be evaluated through more detailed analyses. Overall, starting with a comprehensive inventory of possible transmission benefits during the initial project conceptualization effort would avoid limiting the scope of benefits considered to those for which analytical tools are readily available or only those that have been evaluated traditionally. Potentially significant benefits that are more difficult to estimate should, at a minimum, be analyzed by calculating their likely range of magnitudes.

We offer the following suggestions to planners and policy makers when evaluating the merits of transmission projects:

- *Consider all Benefits*. Production cost simulations have been a tool for many transmission planners, and while such a shift represents significant progress in evaluating the economic benefits of transmission, the results only provide estimates of the short-term dispatch-cost savings under a singular set of generally simplified system conditions. Traditionally, these simplified simulations yield benefit estimates that reflect just a

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[146] As noted in several sources including: (1) UMD CIER, 2010, p. 51; (2) EWEA, 2009, p. 27; (3) Siemens, n.d.; and (4) Wright *et al.*, 2002, p. 5.

[147] IEEE PES, 2005, p. 75.

[148] Siemens, n.d.

[149] Lazaridis, 2005, p. 34.

[150] As noted in several sources including: (1) EWEA, 2009, p. 27; (2) Siemens, n.d.; (3) Lazaridis, 2005, p. 34; and (4) Wright *et al.*, 2002.

[151] PJM 2008 RTEP Update, pp. 8-10.

[152] Pfeifenberger and Newell Direct Testimony, 2010.

portion of total production cost savings and an even smaller portion of the overall economy-wide benefits provided by transmission investments. While not all proposed transmission projects can (or should) be justified economically, we suggest that planners use the checklist to avoid overlooking benefits simply because the traditional tools do not automatically capture these benefits.

- *Define the Scope of Transmission Benefits and the Perspective Taken.* The process for identifying transmission benefits is often limited to the impacts of new projects on customer rates within a utility's system or a planning region. However, a benefit analysis limited to the direct rate impact on customers, especially customers in a single utility footprint or in the planning region, could miss benefits to a region or a larger portion of the economy. Overly narrow benefits evaluations of economic or public policy-driven projects can also miss increased value from improved reliability and ignore benefits that accrue to other market participants or regions. To avoid under- or overstating the total benefits of transmission investments, we recommend that benefit-cost analyses of transmission projects be derived from a perspective that considers the overall benefits (often referred to as "societal" or economy-wide benefits) that accrue to a broad range of market participants and the economy as a whole.

- *Understand Total Benefits Prior to Cost Allocation.* Understanding overall project benefits prior to making cost allocation decisions will enable participants in the planning process to identify those projects that are most beneficial in the long run from an economy-wide perspective. How the distribution of the identified benefits is estimated to accrue to regions, areas, and market participants will ultimately drive both regional and interregional cost allocation—but cost allocation should be addressed only *after* the overall benefits of transmission projects have been considered for inclusion in regional plans. Addressing cost allocation too early in the planning process or strictly on a project-by-project basis can create strong incentives for some market participants and policy makers to understate benefits during the planning and project evaluation process in an effort to reduce their cost responsibility for a project. This can result in rejection of very valuable projects. We also suggest aggregating beneficial transmission projects into larger portfolios of projects to simplify the necessary cost allocation analyses, reduce misperceptions that benefits appear to accrue only to a limited subset of market participants, and facilitate less contentious cost allocation processes.

- *Consider All Regional Benefits in Interregional Planning.* Interregional transmission planning and cost allocation is especially challenging given the tendency of neighboring regions to evaluate interregional projects only based on the subset of benefits that are common to the planning processes of each of the respective regions involved. Only focusing on common benefits results in considering a narrower set of benefits in interregional projects than those considered for region-internal projects. To avoid this "least common denominator" outcome in interregional planning, we recommend that neighboring regions evaluate interregional projects using the full set of potential benefits that are considered for regional projects in each region. This approach would help planners and policy makers to better understand the full benefits of interregional projects to their planning region and to make decisions that are more efficient from an interregional perspective and well-aligned with the interest of all affected regions.

Without an inclusive recognition of all potential benefits by each of the neighboring regions, coordinated interregional planning in compliance with FERC Order No. 1000 would not be able to identify and ensure the development of many projects that benefit two or more regions.

- *Address Uncertainties.* The industry faces considerable uncertainties on both a near- and long-term basis that should be considered in transmission planning. The consideration of near-term uncertainties—such as uncertainties in loads, volatility in fuel prices, and transmission and generation outages—is important because the value of the transmission infrastructure generally is disproportionately concentrated in periods of more challenging, or possibly extreme, market conditions. The consideration of long-term uncertainties—such as industry structure, new technologies, fundamental policy changes, and other shifts in market fundamentals—is important for developing robust transmission plans and investment strategies, valuing future investment options, and identifying "least-regrets" projects. We recommend a more comprehensive planning approach that includes (1) evaluating long-term uncertainties through scenario-based analyses; and (2) evaluating near-term uncertainties within scenarios through sensitivity or "probabilistic" analyses.

- *Consider Long-Term Benefits.* Several methods exist for comparing benefits and costs in the transmission planning processes. The methods currently used by planners and regulators differ by the number of years analyzed (*i.e.*, planning horizons), how benefits are estimated over the short-term and long-term, whether levelized or present values are used in the benefit and cost estimations, and the benefit-to-cost threshold that projects must clear. After analyzing the various methods currently employed in different planning regions, we recommend that the estimated benefits be compared with estimated project costs—either on a present value or levelized annual basis—over a time period, such as 40 or 50 years, that approaches the useful life of the physical assets. Paying attention to how benefits and costs accrue over time across future scenarios will also help planners to optimize the timing of transmission investments from a long-term value perspective.

LIST OF ACRONYMS

1-in-10	One-Day-In-Ten-Years
AEP	American Electric Power
AESO	Alberta Electric System Operator
ALP	Acadiana Load Pocket
APC	Adjusted Production Costs
APS	Arizona Power Service
ATC	American Transmission Company
BPA	Bonneville Power Administration
CAISO	California ISO
CARIS	Congestion Assessment and Resource Integration Study
CBM	Capacity Benefit Margin
CC	Combined Cycle
CEC	California Energy Commission
CEERTS	Cost Effective and/or Efficient Regional Transmission Solutions
CERTS	Consortium for Electric Reliability Technology Solutions
CIEE	California Institute for Energy and the Environment
CIER	Center for Integrative Environmental Research
CMWG	Congestion Management Working Group
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
CT	Combustion Turbine
CVaR	Conditional Value at Risk
DC	Direct Current
DR	Demand Response
DPV2	Devers-Palo Verde No. 2
EFORd	Effective Forced Outage Rate Data
ELCC	Effective Load Carrying Capability
ENS	Energy-Not-Served
EOP	Emergency Operating Procedure

ERCOT	Electric Reliability Council of Texas
ETIP	Energy Technology Innovation Policy
EWEA	European Wind Energy Association
EWITS	Eastern Wind Integration Transmission Study
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operations and Maintenance
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
FTE	Full-Time Equivalent
FTR	Financial Transmission Rights
GADS	Generation Availability Data System
GDP	Gross Domestic Product
GE-MARS	General Electric – Multi-Area Reliability Simulation
GTRPMTF	Generation and Transmission Reliability Planning Models Task Force
HR	Hour
HVDC	High-Voltage Direct Current
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator (Ontario)
IMPLAN	IMpact Analysis for PLANning
IRM	Integrated Resource Management
IRP	Integrated Resource Planning
ISO	Independent System Operator
ISO-NE	ISO New England
ITP	Integrated Transmission Planning
kV	Kilovolt
kW	Kilowatt
kW-yr	Kilowatt year
kWh	Kilowatt hour
LGE&KU	Louisville Gas and Electric Company and Kentucky Utilities Company
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group

LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LSE	Load-Serving Entities
LTS	Long-Term Study
MAPP	Mid-Continent Area Power Pool
MARS	Multi-Area Reliability Simulation
MIG	Minnesota IMPLAN Group
MIS	Mission: Integrated Systems (MIS Energy Management)
MLCC	Multi-Layer Ceramic Chip
MMbtu	Million Metric British Thermal Units
MISO	Midwest ISO
MVP	Multi-Value Project
MW	Megawatt
MWh	Megawatt hour
NCTPC	North Carolina Transmission Planning Collaborative
NEM	National Energy Market
NERC	North American Electric Reliability Corporation
NESCOE	New England State Committee on Electricity
NO_x	Nitrogen Oxide
NPC	Nevada Power Company
NPCC	Northwest Power and Conservation Council
NREL	National Renewable Energy Laboratory
NRRI	Natural Resource Research Institute
NTTG	Northern Tier Transmission Group
NWPP	Northwest Power Pool
NYISO	New York ISO
NYSRC	New York State Reliability Council
O&M	Operations and Maintenance
PIER	Public Interest Energy Research
PJM	PJM Interconnection, Inc.
PLWG	Planning Work Group
PNM	Public Service Company of New Mexico
PNW	Pinnacle West Capital Corporation

PRISM	Parameter-Elevation Regressions on Independent Slopes Model
PRM	Planning Reserve Margin
PtP	Point-to-Point
PV	Photovoltaic
PVD2	Palo Verde-Devers Line 2
RES	Regulatory and Economic Studies
RFC	Reliability First Corporation
RGOS	Regional Generation Outlet Study
RM	Reserve Margin
RMR	Reliability Must Run
RPM	Reliability Pricing MODEL
RPS	Renewable Portfolio Standard
RSP	Regional System Plan
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
RWG	Resource Working Group
SCE&G	South Carolina Electric & Gas Company
SERC	SERC Reliability Corporation
SERTP	Southeastern Regional Transmission Planning Process
SERVM	Strategic Energy Risk Valuation Model
SO_2	Sulfur Dioxide
SOCO	Southern Company
SPP	Southwest Power Pool
TEAC	Transmission Expansion Advisory Committee,
TEAM	Transmission Economic Assessment Methodology
TEPPC	Transmission Expansion Planning Policy Committee
TLR	Transmission Loading Relief
TRG	Technical Review Group
TVA	Tennessee Valley Authority
VOLL	Value of Lost Load
VOM	Variable Operations and Maintenance
VSC	Voltage Source Converter
WACC	Weighted-Average Cost of Capital

WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
WIRES	Working Group for Investment in Reliable and Economic Electric Systems

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APPENDIX A:

CHECKLIST OF ECONOMIC BENEFITS OF TRANSMISSION PROJECTS

Summary Table of Economic Benefits	
Benefit Category	**Transmission Benefit**
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated, including impact of planned and forced generation outages
1a-1i. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
	i. More realistic representation of system utilization in "Day-1" markets
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability <u>or</u> c. Reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	c. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

1. Additional Production Cost Savings				
	Transmission Benefit	**Benefit Description**	**Approach to Estimating Benefit**	**Examples**
1. Additional Production Cost Savings				
--	Reduced impact of forced generation outages	Consideration of both planned and forced generation outages will increase impact	Consider both planned and (at least one draw of) forced outages in market simulations.	Already considered in most (but not all) RTOs
a.	Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads reduces production costs	Either (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for range of hours; or (3) estimate how cost of supplying losses will likely change with marginal loss charges	CAISO (PVD2) ATC Paddock-Rockdale SPP (RCAR)
b.	Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion	Introduce data set of normalized outage schedule (not including extreme events) into simulations or reduce limits of constraints that make constraints bind more frequently	SPP (RCAR) RITELine
c.	Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, or multiple outages.	Calculate the probability-weighed production cost benefits through production cost simulation for a set of extreme historical market conditions	CAISO (PVD2) ATC Paddock-Rockdale
d.	Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns	Use SPP suggested modeling of 90/10 and 10/90 load conditions as well as scenarios reflecting common regional weather patterns	SPP (RCAR)
e.	Reduced costs due to imperfect foresight of real-time conditions	Reduced production costs during deviations from forecasted load conditions, intermittent resource generation, or plant outages	Simulate one set of anticipated load and generation conditions for commitment (e.g., day ahead) and another set of load and generation conditions during real-time based on historical data	
f.	Reduced cost of cycling power plants	Reduced production costs due to reduction in costly cycling of power plants	Further develop and test production cost simulation to fully quantify this potential benefit ; include long-term impact on maintenance costs	WECC study
g.	Reduced amounts and costs of ancillary services	Reduced production costs for required level of operating reserves	Analyze quantity and type of ancillary services needed with and without the contemplated transmission investments	NTTG WestConnect MISO MVP
h.	Mitigation RMR conditions	Reduced dispatch of high-cost RMR generators	Changes in RMR determined with external model used as input to production cost simulations	ITC-Entergy CAISO (PVD2)
i.	More realistic representation of system utilization in "Day-1" markets	Transmission offers higher benefits if market design is utilizing the existing grid less efficiently	Use flowgate derates (in addition to the traditional use of hurdle rates between balancing areas) in production cost simulations to more realistically approximate system utilization in "Day-1" markets	MISO "Day-2" Market benefit analysis

2–3. Reliability and Resource Adequacy Benefits and Generation Capacity Cost Savings				
Transmission Benefit		**Benefit Description**	**Approach to Estimating Benefit**	**Examples**
2. Reliability and Resource Adequacy Benefits				
a.	Avoided or deferred reliability projects	Reduced costs on avoided or delayed transmission lines otherwise required to meet future reliability standards	Calculate present value of difference in revenue requirements of future reliability projects with and without transmission line, including trajectory of when lines are likely to be installed	ERCOT All RTOs and non-RTOs ITC-Entergy analysis MISO MVP
b.	Reduced loss of load probability Or:	Reduced frequency of loss of load events (if planning reserve margin is not changed despite lower LOLEs)	Calculate value of reliability benefit by multiplying the estimated reduction in Expected Unserved Energy (MWh) by the customer-weighted average Value of Lost Load ($/MWh)	SPP (RCAR)
c.	Reduced planning reserve margin	Reduced investment in capacity to meet resource adequacy requirements (if planning reserve margin is reduced)	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to reduced resource adequacy requirements	MISO MVP SPP (RCAR)
3. Generation Capacity Cost Savings				
a.	Capacity cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needs	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to capacity savings from reduced energy losses	ATC Paddock-Rockdale MISO MVP SPP ITC-Entergy
b.	Deferred generation capacity investments	Reduced costs of generation capacity investments through expanded import capability into resource-constrained areas	Calculate present value of capacity cost savings due to deferred generation investments based on Net CONE or capacity market price data	ITC-Entergy
c.	Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location	Calculate reduction in total costs from changes in the location of generation attributed to access provided by new transmission line	CAISO (PVD2) MISO ATC Paddock-Rockdale

4–7. Market, Environmental, Public Policy, and Economic Stimulus Benefits				
Transmission Benefit		Benefit Description	Approach to Estimating Benefit	Examples
4. Market Benefits				
a.	Increased competition	Reduced bid prices in wholesale market due to increased competition amongst generators	Calculate reduction in bids due to increased competition by modeling supplier bid behavior based on market structure and prevalence of "pivotal suppliers"	ATC Paddock-Rockdale CAISO (PVD2, Path 26 Upgrade)
b.	Increased market liquidity	Reduced transaction costs and price uncertainty	Estimate differences in bid-ask spreads for more and less liquid markets; estimate impact on transmission upgrades on market liquidity	SCE (PVD2)
5. Environmental Benefits				
a.	Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emission reductions not already reflected in production cost savings	NYISO CAISO
b.	Improved utilization of transmission corridors	Preserve option to build transmission upgrade on an existing corridor or reduce the cost of foreclosing that option	Compare cost and benefits of upsizing transmission project (e.g., single circuit line on double-circuit towers; 765kV line operated at 345kV)	
6.	**Public Policy Benefits**	Reduced cost of meeting policy goals, such as RPS	Calculate avoided cost of most cost-effective solution to provide compliance to policy goal	ERCOT CREZ ISO-NE, CAISO MISO MVP SPP (RCAR)
7.	**Employment and Economic Development Benefits**	Increased full-time equivalent (FTE) years of employment, economic activity related to new transmission line, and tax revenues	A separate analysis required for quantification of employment and economic activity benefits that are not additive to other benefits.	SPP MISO MVP

8. Other Project-Specific Benefits				
	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
8. Other Project-Specific Benefits				
a.	Storm hardening	Increased storm resilience of existing grid transmission system	Estimate VOLL of reduced storm-related outages. Or estimate acceptable avoided costs of upgrades to existing system	ITC-Entergy
b.	Increased load serving capability	Increase future load-serving capability ahead of specific load interconnection requests	Avoided cost of incremental future upgrades; economic development benefit of infrastructure that can	
c.	Synergies with future transmission projects	Provide option for a lower-cost upgrade of other transmission lines than would otherwise be possible, as well as additional options for future transmission expansions	Value can be identified through studies evaluating a range of futures that would allow for evaluation of "no regrets" projects that are valuable on a stand-alone basis and can be used as an element of a larger potential regional transmission build out	CAISO (Tehachapi) MISO MVP
d.	Increased fuel diversity and resource planning flexibility	Interconnecting areas with different resource mixes or allow for resource planning flexibility		
e.	Increased wheeling revenues	Increased wheeling revenues result from transmission lines increasing export capabilities.	Estimate based on transmission service requests or interchanges between areas as estimated in market simulations	SPP (RCAR) ITC-Entergy
f.	Increased transmission rights and customer congestion-hedging value	Additional physical transmission rights that allow for increased hedging of congestion charges.		ATC Paddock-Rockdale
g.	Operational benefits of HVDC transmission	Enhanced reliability and reduced system operations costs		

Summary of Peer Review

of

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

The discussion that follows has been prepared by Professor Ross Baldick, Dr. Keith Casey, Dr. Gary Stern and Dr. Richard Tabors at the request of WIRES.[1] We have reviewed The Brattle Group report independently and have had the opportunity of several joint discussions among the review team and with the principal authors of the report.

Overview

We commend WIRES for commissioning the study and The Brattle Group for undertaking the effort. The Brattle Group authors have provided a thorough review and cataloguing of the multiple benefits of transmission investment. The report offers, predominantly from a societal perspective, the methodologies required to account adequately for the multiple benefits of transmission, balanced with those of expansion in generation or demand-side management. The report itself is clear in its statement of what is considered and what is not. However, it is not surprising that this cataloguing of the benefits of one major sub-system of the power system has raised almost as many new avenues and issues for further thought and research as it has answered. As reviewers, we have provided comments on the content of the report but also on what still needs to be considered in the transmission investment decision-making processes.

In our review, we focus on three areas of specific contribution of the *Benefits of Electric Transmission* report.

- Cataloguing of the numerous economic, environmental and societal benefits provided by transmission investments;
- Framing a general methodology for considering the totality of the benefits relative to transmission costs; and

[1] Dr. Ross Baldick, Professor and Leland Barclay Fellow, Department of Electrical and Computer Engineering, The University of Texas; Dr. Keith Casey, VP Market & Infrastructure Development, The California ISO; Dr Gary Stern, Director of Regulatory Policy, Southern California Edison Company; Dr. Richard Tabors, President, Across the Charles and Director Utility of the Future Project, MIT Energy Initiative.

The opinions expressed in this review are those of the authors and do not necessarily reflect the opinions of the institutions or universities of which they are a part.

- Explicitly separating the calculation of the benefits of transmission from the issues associated with allocation of the costs of transmission development.

We also provide a discussion of the need for the development of a more comprehensive and optimal decision-analytic framework for assessing the overall system benefits of alternative transmission investments.

Cataloguing of Societal Benefits of Transmission

The Brattle Group authors have presented what is arguably the most complete catalogue of the benefits of transmission investments that has been assembled to date. More importantly, the cataloguing has been structured such that the discussion in the text flows by logical steps from the most commonly used and most easily estimated benefits to those that are less easily (if at all) estimated but which, the authors argue and we agree, should be considered in benefit evaluations.

The report begins with the traditional methods and inclusions of total production cost savings that capture the reductions of the variable costs of generation alone. Importantly it then extends the discussion to reduction in transmission losses, capital requirements, the costs associated with cycling of units, operating reserves and other ancillary services, and reduction in reliability-must-run generation.

The report retains an overall flow that moves through eight major categories of benefits focusing on those that are conceptually most obvious to those that are least frequently discussed and likely to be the most difficult to estimate using traditional cost and benefit analysis techniques. Moving from production costs savings to reliability and resource adequacy is the first step, followed by generation capacity cost savings, and then market, environmental, public policy, employment and economic stimulus, and project-specific benefits. Estimation of such benefits goes beyond the capabilities of standard production cost software, implying a need for development of methodologies to evaluate these benefits together with enhancement of industry tools.

The authors arrive at a range of conclusions and summary points with regard to the benefit measures identified. Two overall conclusions flow through the benefit discussions in the document.

- Not looking broadly at the benefits of transmission asset development within the structure of the power system will tend to underestimate – and potentially significantly – the value of transmission investments. This underestimation may be more serious for transmission assets than the underestimation of analogous benefits in other sub-systems. That is, the underestimation will tend to systematically bias against transmission solutions.

- Not looking at the breadth of benefits because “they might be difficult to estimate” relative to the benefits of other investment opportunities within the power sector is not a sufficient justification for ignoring what could well be some of the most critical of the advantages of transmission investments.

A General Methodology for Assessment of Transmission Benefits

The authors propose a four stage approach for considering transmission benefits and cost allocation that consists of the following:

1. Identify potential transmission projects and develop a comprehensive list of their likely benefits.
2. Estimate the monetary value of as many of the identified benefits as practical.
3. Determine whether the proposed transmission investments would be beneficial overall.
4. Address cost allocation.

In general, we support the key principles underlying this four stage approach. Specifically;

- Consideration early in the process of a broad range of potential transmission projects over as broad a region as possible before rushing to evaluate an initial preferred solution.
- Identifying a full set of benefits and estimating the monetary value of as many of the identified benefits as practical.
- Identifying beneficial projects by considering of societal benefits relative to costs and potential synergies of considering several projects jointly.
- For the identified portfolio of beneficial projects, using estimates of the distribution of the identified benefits to inform cost allocation decisions.

However, we believe the proposed evaluation approach could be enhanced by considering the following:

Identification of System Needs/Planning Objectives **–** We believe the first stage of a planning process should include explicit consideration of the potential needs/drivers for the new transmission (e.g., identify public policy objectives, reliability needs, baseline congestion projections, etc).

Consideration of Non-Transmission Alternatives - The authors’ note that the proposed brainstorming session should recognize non-transmission alternatives. We agree that consideration of non-wire options (generation, demand response, storage, etc.) should be considered and recommend that the process of doing so should be defined explicitly and in a manner that avoids systematic biases in the evaluation of transmission solutions vis a vis other options.

Need for a Systematic Approach for Identifying and Evaluating Transmission Projects – As we discuss in greater detail below, the proposed process for identifying and evaluating the benefits of transmission projects relies heavily on the transmission planner's initial judgment about the value of a potential project or combinations of projects. Ultimately, we believe a more systematic approach is needed to identify optimal transmission projects and synergistic benefits of joining individual projects.

Separation of the Estimated Benefits of Transmission Enhancements from the Allocation of Their Costs

The report correctly focuses on the incentive problems associated with tying cost allocation to the calculated benefits of particular parties or regions. The proposed solution of first calculating the benefits and only subsequently assessing the cost allocation for a portfolio of beneficial projects is a necessary but not sufficient condition to solve this incentive problem. One of the key challenges is that added transmission is very likely to benefit different constituents differently. Relieving congestion may be societally beneficial, but when examined in isolation, load in an area where generation is "trapped" gets lower prices and may gain from the congestion and thus have a negative benefit from the transmission investment, whereas generation in that same area, again examined in isolation, may be harmed by the congestion and would receive a benefit from the transmission investment. Economic benefit to the region may accrue, but the utility's ratepayers might still see a net increase in rates depending on the allocation of costs. While the overall society benefits, there may be pockets of a utility's ratepayers that do not benefit. In addition, as the Brattle authors note, and possibly far easier to say than to implement, to ensure a fair assessment of the benefits of transmission additions and their distribution, it would be desirable to have the entity responsible for estimation of benefits be an independent "honest broker" without any vested interest in the outcome.

The authors suggest in their cost allocation stage of the evaluation process that "aggregating beneficial transmission projects across a region into a portfolio of projects is advisable before determining cost allocations because the benefits associated with a more geographically-diverse, larger portfolio of transmission projects will tend to be more evenly distributed." We do not believe this will necessarily be the case and suspect that stakeholders within most planning regions will want to understand how they benefit from individual major elements/segments of a proposed set of transmission projects.

We do agree that disaggregating the benefits of a combined set of transmission projects that are highly interdependent and synergistic is problematic in that the benefits of any individual element depends on whether the other elements are assumed developed as well. In such cases, we believe the combined set of transmission projects should be viewed as one holistic project and the costs allocated to each impacted planning region should be allocated based on the estimated benefits it receives from the total project. In cases where individual transmission projects have very few interdependencies, cost allocation should be based on assessing the regional benefits of each project separately so that the costs allocated to each planning region are proportional to the benefits received.

Other Considerations and Methodological Questions

As we discussed briefly above, the *Benefits of Electric Transmission* raises a number of questions that go well beyond the acknowledged scope and objective of the current report. The reviewers believe these questions should be raised in the context of providing for a greater level of completeness to the larger topic of assessment of transmission investments, acknowledging that there are no quick and easy answers. Raising these questions in no manner diminishes the usefulness or quality of the current effort but rather points to both the complexity of the issues surrounding decisions for transmission investment as well as the fact that only limited effort has been applied to date to developing the analytic technologies and overall methodological approach to transmission investment planning.

The electric power system is a complex, interconnected whole. While the interconnection may be argued to be the transmission system, the whole incorporates generation (both central and distributed), storage (again central and potentially distributed), distribution in all of its complexity, and the interaction with end users at all levels and at all levels of complexity in use and control.

It is difficult, if not impossible, to fully evaluate the benefits of transmission without reaching into the competing benefits of investments in other sub-systems of the power system. Technology is not standing still in terms of the transmission system or in terms of the other sub-systems of the power system. Two examples of changes whose impacts upon asset growth in transmission have yet to be quantified are:

- The impact of significant investment in distributed generation and potentially storage within the distribution system. These changes are being brought about by public policy decisions combined with a dramatic expansion in communications and controls allowing for the development of distributed energy systems that interact with the larger utility system.

- The impact of sensing and control of the transmission system that allows for dynamic reconfiguration of the topology of the transmission system. Often referred to as "line switching," the benefits have been known by system operators for decades. It is only with increased monitoring, advances in analytic techniques, and computation speed that these concepts can be brought into the operational time frame.

Technological changes are adding points of pressure to the power system in general and specifically to the transmission sub-system as the interchange network that allows the system to remain balanced.

If there is a single missing element in the puzzle of evaluation of the benefits of transmission it is the lack of a systematic methodology for benefit evaluation. The Brattle Group authors and we have suggested an overall approach to the process. What follows is our – albeit brief – discussion of what is needed to take the next step in development of a systematic and reproducible methodology for transmission benefit (and cost) evaluation.

We acknowledge that there is no comprehensive methodology for evaluating transmission (or more generally systems level) investments in the power sector. During the 1980s and 1990s relatively little new transmission was built in the United States. The decision to construct new transmission revolved around individual projects that were needed to meet applicable reliability criteria or could be evaluated using relatively simple with/without economic analysis in conjunction with the standard tools of production cost modeling and power flow. This has changed in the last decade with objectives of increased renewable energy penetration and the need to replace aging transmission system assets. The implication is that there will be large investments in transmission construction that must face an uncertain future of alternative scenarios for carbon legislation, fuel cost, and demand growth. The CREZ transmission project in ERCOT, for example, will cost around $7 billion. Such expansions consist of large numbers of individual elements that interact synergistically. However, traditional tools such as power flow and production cost modeling have not yet been augmented with decision support tools or frameworks that could more effectively address the far more complex decision analysis that implicitly needs to be done for projects like CREZ.

The development of a formal decision support framework could significantly benefit current planning processes by systematically integrating (if not automating) many of the calculations needed to consider the detailed alternatives and winnowing out the best (or better) alternatives and eliminating the less good alternatives, freeing transmission planners to focus more effectively on bigger picture issues. A decision support methodology would begin with geographical information system input and use known land use information to roughly plan various alternative routes for new transmission assets. It would include information on current electrical system constraints and, as such, would be a tool that would provide a first cut at physical and electrical parameters for various alternative routes that would be invaluable in winnowing out the particular lines and assets that collectively satisfy the planning constraints at least cost. Such an analytic structure would be dynamic in that it would consider multiple future scenarios over an extended planning horizon.

The result of such a structure would, as pointed out by The Brattle Group study, include information about the quality of the solution and uncertainties in outcomes in contrast to current planning processes that do not systematically consider alternative future scenarios and provide very little assurance that construction plans are at least cost.

While we realize no such comprehensive structure exists in transmission planning to date, we believe that analytical tools based upon developments in advanced computing and optimization such as have been seen in other segments of the industry (e.g., operations/market dispatch) could help inform the design of improved analytical and decision frameworks for transmission planning. While such formal advanced analytical methods will not lend themselves to capturing all of the potential benefits of a transmission project (e.g., wider economy benefits), they should be designed to be able to capture the most important of the potential benefits. This will lead to better decision making relative to what too often occurs today.

Summary and Conclusions

In our view, the *Benefits of Electric Transmission* report provides a very useful, thorough cataloguing of both the easy and the difficult-to-measure benefits of transmission investments. As pointed out in our review, there is work still to be done in developing methodologies to systematically evaluate transmission investments within the totality of the power system. We believe that the advances in other segments of the industry can and will help inform the design of improved analytical and decision frameworks for transmission planning.

Even with such advances in evaluation techniques and consideration of a broader range of benefits, the process of evaluating transmission investment is and will remain contentious. There will be parties to the process who will legitimately have interests not aligned with the broad social benefit. The reality of today's combined State and Federal regulatory environment assures there will be specific instances where ratepayer interests can and will continue to trump the overall social welfare benefits in specific instances and that the role of the FERC will continue to be a point of contention, particularly when FERC allows transmission return on investments that are above currently-authorized returns by the individual states.

These are the realities of transmission investment. That said, however, understanding the benefits of transmission investment in all of their complexity and uncertainties represents a first and most critical step.

Reviewer Biographies

Ross Baldick is Professor and Leland Barclay Fellow in the Department of Electrical and Computer Engineering at The University of Texas at Austin. He received his B.Sc. and B.E. (medal (pr. acc.)) degrees from the University of Sydney, Australia and his M.S. and Ph.D. from the University of California, Berkeley. From 1991-1992 he was a post-doctoral fellow at the Lawrence Berkeley Laboratory. In 1992 and 1993 he was an assistant professor at Worcester Polytechnic Institute.

Dr. Baldick received a National Science Foundation Research Initiation Award in 1993; a National Science Foundation Young Investigator Award in 1994; and Engineering Foundation Faculty Award, University of Texas at Austin, in1997, and has been the Principal Investigator on approximately 20 funded research projects. He has published over fifty refereed journal articles, made presentations on over seventy-five different topics, and has research interests in a number of areas in electric power. He received the Best Presentation in Energy Sponsored Sessions Award, INFORMS Conference, Atlanta, Georgia, October 2003 (with Stathis Tompaidis and Sergey Kolos) and the IEEE Power Engineering Society, Power System Analysis, Computing, and Economics Technical Committee Prize Paper Award, in 2006 (with Richard P. O'Neill, Udi Helman, Michael H. Rothkopf, and William Stewart, Jr.)

Keith Casey, Ph.D. is Vice President, Market and Infrastructure Development at the California Independent System Operator Corporation (ISO). The division is responsible for developing efficient markets and effective infrastructure planning. Part of the organization's start-up team in 1997, Dr. Casey served as Director, ISO Department of Market Monitoring from 2005 to 2009 and played a key role in designing a new market and monitoring program that guards against manipulation and fosters healthy competition.

Since 2009, Dr. Casey has served as Vice President, Market & Infrastructure Development. He is responsible for developing market design and infrastructure policies and overseeing the transmission planning and generation interconnection process to ensure all of these critical functions evolve to effectively address the changing needs of the industry and facilitate California's transition to a greener and smarter electric grid. Dr. Casey also serves on the Western Electricity Coordinating Council Board of Directors. Dr. Casey received his bachelor's degree in economics from the University of California San Diego. He has a master's degree in economics from the University of Maine and earned his doctorate in agricultural and resource economics with a specialization in environmental economics from the University of California Davis.

Gary Stern is the Director of Regulatory Policy for Southern California Edison Company (SCE). Reporting to the Senior Vice President of Regulatory Policy & Affairs, he manages a division responsible for the development of policy in matters relating to the California Public Utilities Commission, California Energy Commission, California Independent System Operator, and the Federal Energy Regulatory Commission. His organization is also responsible for case management associated with proceedings with all of these entities. Previously, Gary directed SCE's resource planning, market design and analysis, and strategic project groups. Gary Stern holds a Ph.D. in Economics from the University of California at San Diego. He has an M.A. in Economics, and a B.A. in mathematics also from UC San Diego.

Richard D. Tabors, Ph.D. is an economist and scientist with 35 years of domestic and international experience in energy planning and pricing, international development, and water and wastewater systems planning. He is currently President and Principal of *Across the Charles* an energy, water and wastewater consulting group in Cambridge, Senior Consultant at Greylock McKinnon of Cambridge and an Affiliate of the MIT Energy Initiative. Prior to forming *Across the Charles* Dr. Tabors was Vice President of Charles River Associates.

From 1976 until 2006 Dr. Tabors held a variety of position at Massachusetts Institute of Technology culminating in the title of Senior Research Engineer and Senior Lecturer. These positions involved research development and supervision as well as academic teaching and included being Assistant Director of the power systems engineering laboratory (LEES) and associated director of the Technology and Policy master's program. Prior to MIT Dr. Tabors was Assistant Professor of City and Regional Planning and a member of the teaching faculty of the College of Arts & Sciences at Harvard University. At present he is a visiting professor of Electrical Engineering at the University of Strathclyde, Glasgow, Scotland.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service lists compiled by the Secretary in above-listed proceedings.

Dated at Rensselaer, NY this 29th day of December, 2014.

/s/ Joy A. Zimberlin

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